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Improvement of the Social Optimal Outcome of Market Integration of DG/RES in European Electricity Markets

Assessment of interactions between the economics of distributed generators, distribution system operators and markets

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Project objectives

The IMPROGRES project aims to identify possible improvements in the social optimal outcome of market integration of distributed generation (DG) and electricity production from renewable energy sources (RES-E) in European electricity markets. This will be achieved by:

- Identification of current interactions between DG/RES businesses, distribution system operators (DSOs) and energy markets in coping with increased DG/RES penetration levels.
- Developing DG/RES-E scenarios for the EU energy future up to 2020 and 2030.
- Quantifying the total future network costs of increasing shares of DG/RES for selected network operators according to the DG/RES-E scenarios.
- As a comparison to regular DSO practices, identify cost minimising response alternatives to increasing penetration levels of DG/RES for the same network operators.
- Recommend policy responses and regulatory framework improvements that effectively support the improvements of the socially optimal outcome of market integration of DG/RES in European electricity markets.

Project partners

- Energy research Centre of the Netherlands (ECN), The Netherlands (coordinator)
- Liander NV (previously called: Continuon Netbeheer), The Netherlands
- Institut für Solare Energieversorgungstechnik (ISET), Germany
- MVV Energie, Germany
- Risø National Laboratory for Sustainable Energy, Technical University of Denmark (Risø DTU), Denmark
- Union Fenosa Distribucion, Spain
- Universidad Pontificia Comillas, Spain
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1. Executive summary

1.1 Background

Renewable energy sources for electricity generation (RES-E) and other distributed generation (DG) technologies, such as local combined heat and power (CHP) power plants, are among the core elements in reducing greenhouse gas emissions. Besides, they help achieving other EU policy targets such as security of supply. With an increasing penetration, the focus shifts from direct support schemes to efficient market integration. Incentives should support flexibility based on market price signals in the short term, and long term distortion of markets should be minimised. Locational signals for DG/RES investments should include interaction with distribution and transmission grids. Regulation of network companies and support schemes should be coordinated to secure that incentives for efficient integration exist. One of the key issues is the interaction with distribution system operators (DSOs), which constitutes the physical connection between a DG/RES unit and the remaining power system. The design of support schemes and national distribution network regulation is to the discretion of the individual EU Member States. This report analyses the economic factors of DG/RES and DSO operations with a focus on their interactions. Both points of view are confronted with each other to derive regulatory implications for the single aspects of their interaction. Based on the relevant regulation affecting DG operators' and DSOs' operations in different countries, existing grid codes and the changes to these rules that have been proposed, we aim to identify which rules could be implemented in order to provide DSOs with the right incentives to facilitate and pass on incentives to DG to install capacity and integrate operation of DG/RES in a way that increases total efficiency. Different possibilities for designing the regulation of the DG producers' and DSOs' operations in a way that increases the incentives for these entities to integrate DG/RES in the electricity system have been analysed. In the following, the influence of network regulation and application of support schemes on cost and revenue streams of DG operators and DSOs are illustrated by means of a simple analytical modelling approach. Subsequently, some light will be shed on the qualitative implications of market interactions and market power.

This report constitutes Deliverable D3 of the dissemination activities of Work Package 2 of the IMPROGRES project, dealing with current DG/RES, DSO and market interactions. The D3 Deliverable discusses the interactions between the aforementioned entities and illustrates them with five cases: West Denmark, the Netherlands, Germany, Spain and the United Kingdom.

1.2 Approach and structure

In order to deal with the aforementioned questions, this report consists of the following parts:

1. A detailed analysis of DSO and DG/RES economics with focus on the relation to the respectively other party.

This section is divided in several subsections, each of them corresponding to one of the several aspects of the interaction between DSOs and DG/RES. Specifically, the topics that are dealt with include the level of integration between them, network regulation, remuneration of DG/RES, the participation of DG/RES in power markets and the provision of ancillary services. Moreover, the allocation of costs arising from DG/RES integration, the planning of grid expansion, the impact of DG on the quality of service, as well as the incentives for DSOs to introduce innovations are addressed. Within each of the aforementioned sections, first a conceptual analysis of the potential impacts (both positive and negative) that the corresponding regulation may have on the incentives for DSOs to integrate DG/RES generation is provided. Afterwards, the existing regulation in place in the focus countries is discussed. Finally, regulatory implications are highlighted.

2. A revenue stream model

   This section describes a simple model to analyse the impact on DG revenue of allowing DG to participate in both day ahead and regulating markets under different support schemes. A second line of analyses deals with the incentive interactions with the DSO from network losses and connection charges with the help of another simple model.

3. Economic impacts of DG/RES integration on power markets

   This part addresses several topics as the integration into spot and regulating markets and the impact on market power in a predominantly qualitative manner.

1.3 Main findings

Integration of DG/RES and DSO operations

Vertical integration between network operators, in particular DSOs, and DG/RES generation influences the incentives of market actors in different directions. The level of integration between DSOs and DG/RES generation is subject to the unbundling requirements by the EU. Four levels of unbundling can be distinguished: ownership unbundling, legal unbundling, functional unbundling, and unbundling of accounts. Legal and functional unbundling are mandatory for all DSOs, but Member States can apply an exception rule for small DSOs. Regulation on provisions governing the unbundling of DSOs has to balance the danger of a vertically integrated DSO exercising local market power (e.g., aggravation of network access for competitors in a rural network) against the financial and operational burden unbundling imposes on small DSOs that have to sustain against large-scale generators in the European electricity market.

Network regulation

The regulation and level of network charges are pivotal for the access conditions of DG/RES generators; this applies in particular to third party access for generators not owning and operating networks themselves. Network charges can be differentiated with respect to connection charges to be paid for obtaining the initial connection to the network, and the network tariff.

Connection charges can be separated according to DG/RES cost participation: for shallow charges, they pay only the direct cost of connection, whereas they pay all linked network upgrade costs at the distribution and transmission level under deep connection charges. Shallowish charges are an intermediate. Use-of-System charges (UoS) are variable and applied per transmitted kilowatt-hour. However, charging methodologies and target groups (consumers only or consumers and generators) depend on national legislation. The income of TSOs and DSOs consists of the sum of all network charges and tariffs and can itself be subject to an overall cap to incentivise the DSO towards more economical operations. Results of the project expert survey show that a multitude of different network regulation approaches – economic network regulation as well as connection and use-of-system charges – are followed in practice. Shallow connection charges with no generator UoS charges are optimal to foster a fast growth of DG/RES units, but neglect DSO system integration aspects.

Remuneration of DG/RES

The operation of most DG/RES units is not yet economically viable under market conditions. Member States support these technologies therefore, but with different support schemes. In contrast to investment support, which is mainly granted for technologies which are distant from market integration, operating support is the dominant instrument for more mature technologies. These are subdivided into quantity-based schemes (where the regulator defines a target of a renewable generation quota that needs to be met) and price-based schemes. The latter one can be implemented as a feed-in tariff where the regulator guarantees a certain income for every generated kilowatt-hour (kWh), or as a price premium scheme. In the latter case, a premium on top of market prices is granted. The predominant support scheme in Germany is the feed-in tariff, whereas Denmark and the Netherlands apply price premiums and Spain a combination of feed-in tariffs and premiums. In the UK, a system of green certificates is in place whereby generation companies are forced to produce a certain fraction of their total output from renewable energy sources. RES generators' revenues result from the sale of their green certificates on top of actual power sales. The DSO is not directly affected by the choice of support scheme, only by indirect effects as resulting local DG/RES penetration growth. Production or generation based support schemes will concentrate DG/RES development in the most favourable generation areas whereas more differentiated support schemes or investment subsidies will spread the development more with lower cost impacts on the DSOs but also lower generation efficiency.

Market participation of DG/RES

DG/RES operators can access power markets either by making single units participate directly or by aggregating several units to a portfolio which matches the usual criteria for market participation. The incentive to participate in power markets depends on the kind of operating support: under price premiums and quota schemes, DG/RES operators market their electricity themselves. However, special rules for small generators – e.g., lower fixed annual energy exchange fees – can facilitate integration. Such special fees are implemented in the Nordic and German energy exchanges. A crucial factor for active network management by the DSO is whether it is informed about the generation schedule. This information is necessary for planning actions of activating demand response or adjusting generation schedules including the optimisation of local storage options. In the planning perspective, active management includes also investment planning so as to balance the benefits and costs of expected DG/RES investments.

Participation in ancillary services

Ancillary services comprise a wide field of necessary network services, such as the provision of frequency control, voltage control, black-start capability, island operation, solution of network constraints and organising balancing mechanisms. DSOs do not operate any ancillary service markets until now, but participation in regulating markets is possible in most countries. Minimum capacity requirements are a hindrance for DG/RES market entrance. Most local voltage problems could be solved through active cooperation of DG in voltage control services. A pro-active DSO would then take over part of the responsibilities for system stability from the TSO and can thus extend its responsibilities.

Allocation of costs arising from DG/RES integration

The costs a DSO faces due to DG/RES integration, if fully acknowledged in network regulation, are generally recovered through deep or shallowish connection charges or Use-of-System charges. The level and kind of costs depend highly on the penetration and local conditions. Generally, none of the survey countries considers compensation payments for DG/RES due to advantages DSOs have because of these units. The impact of network costs, losses and quality of service is not taken into account in the Netherlands and Spain. German regulation considers it implicitly. In Denmark, necessary new investments due to DG/RES lead to a higher revenue cap, whereas network losses and the impact on quality of service are not considered. The UK regulatory regime regards DG as an explicit cost factor and, additionally, allows a higher revenue cap due to innovation activities and registered power zones (where a more active network management approach can be followed).

Planning of grid expansion with regard to DG/RES

In order for DG to be able to deter or delay possible future network investments, it is necessary for the DSOs to make sure that DG will be producing/not producing when it is required by the system. Thus, some level of controllability of the output of DG by DSOs is necessary. DSOs in Denmark and the UK can sign contracts with DG/RES generators. This allows the former to partially control the output of the latter. Regulation in other countries does not consider this possibility. DSOs in most countries do not consider the possibility of avoiding network reinforcements because of the presence of DG. What is more, there are some countries, like the Netherlands, where DSOs have traditionally considered DG to be a potential source of problems. An exception to this rule is the UK, where DSOs seem to be encouraged to take DG into account in the planning process.

Impact of DG/RES integration on the quality of service

Quality of service levels have a direct impact on the allowed DSO revenues in most of the regarded countries. DG/RES units can have positive or negative effects on this, which also depends on network operation. If part of the potential benefits brought about by DG in terms of quality of service were reflected in DSOs' revenues, the latter would consider the possibility of connecting more DG and interacting with it in order to reduce supply interruptions. Implementing DG controllability and realizing the potential for increase in quality of service would probably require the use of active network management techniques, such as balancing control capabilities, in situations where transmission grids are disconnected or in black start situation. DG/RES could also keep part of the benefits caused by their contribution to quality of service levels for themselves.

Incentives for innovation

In general, innovations are expected to support the development of a conventional, "passive" DSO to an "active" DSO considerably. This would benefit DG/RES integration. Innovation incentives could be associated with the reduction of grid expansion and operation costs (energy price and losses) and the increase of service quality levels. Since the investments in R&D and innovative activities are risky, the regulator should allow cost recovery through the revenue cap regulation or provide financial support in the first stages of the innovation process until the benefits resulting from the introduction of these innovations become clear.

Revenue stream model

DG/RES revenues are firstly determined by the level of the support. Secondly, revenues are affected by electricity market developments depending on the type of support scheme implemented. Different support schemes can provide the same level of long term support, but at the same time have different risk allocation characteristics in the shorter term. DG investors generally favour up front support with the lowest risk, but it is rather the active integration of DG in the markets that results in system efficiency gains, especially in the case of flexible and controllable DG technologies. Market based subsidy schemes are to be preferred for efficiency reasons. The effect of DG investment on distribution grids within the same power market is independent of the choice of subsidy scheme.

Allowing DG to take part in the regulating power markets will produce benefits to the DG operator if regulating market prices are higher than wholesale electricity market prices. Allowing this flexible allocation of generation between the markets will produce overall economic benefits in a similar way as allowing transferring generation in time by the simple exposure to market prices for DG on the day ahead markets. The participation on two markets is assumed to produce no additional costs to the DSO. Transaction costs artificially set above real costs might obstruct efficient deployment of DG technologies in these markets.

The network elements of the revenues and the interaction between DG and DSO can be addressed by possible reductions in connection charges as a response to cost savings for the DSO. An efficient network regulation should allow the DSO to provide investment incentives to DG up to a level of DG penetration where network losses can no longer be reduced. This means that the reduced network losses should be kept as increased profits for the DSO under the regulation regime allowing it to pass a share of this to the DG in the form of, for example, reduced connection charges. Connection charges could still be regulated with a maximum equivalent to shallow or shallowish connection charges. If, by contrast, network loss reduction was deducted from the price or revenue cap, then there would be no incentive for an efficient level of DG in the different DSO grids. An alternative to reduced connection charges could be location dependent UoS charges.

Economic impacts of DG/RES integration on power markets

The power market is divided into several submarkets according to the time to delivery. Large amounts of fluctuating generation with low marginal costs have a strong impact on spot market prices. Intraday spot markets are a means of correcting the day-ahead plans without having to use the regulating power market. It can generally be assumed that higher DG/RES penetration leads to a higher usage of these markets because market participants want to correct forecast errors without having to use the more expensive regulating markets. In a geographically small market, such forecast errors will show a high correlation among all units of a generation technology and have a uniform impact on market prices.

Regulating power is traditionally supplied by hydro storages and large condensing power plants and organized centrally by the respective TSO. There are better possibilities for DG/RES to participate in minute and secondary regulating power markets as these are rather short-term based. In most cases, this requires grouping them to virtual power plants and controlling them with necessary communication infrastructure. Participation in primary regulating power markets is even under such conditions hardly achievable because the offered capacity has to be available during the whole period.

It seems that concerns about market power decrease strongly when the capacity bid into the market is divided between as many actors as possible. If DG/RES capacities are not marketed through the trading divisions of large vertically integrated companies, they can help to mitigate market power.

2. Economic analysis of DG/RES and DSO operations

This chapter deals with the impact of network regulation and support schemes for DG operators and DSOs, respectively. In order to point out the - partially conflicting - incentives of these market actors involved, this chapter provides a qualitative analysis of the status quo of existing regulation and how it impacts DG operators and DSOs. This qualitative analysis will be supplemented by a simple analytical approach on the impact on revenue streams in the subsequent chapter.

2.1 Level of integration between DSOs and DG/RES generation

Vertical integration (through ownership) between network operators, in particular DSOs, and DG/RES generation influences the incentives of market actors in different directions. On the one hand, there is the importance of providing fair and non-discriminatory access to the network to third parties. Networks constitute essential facilities with natural monopoly characteristics; this necessitates the independence of DSOs so as to guarantee a level playing field and equitable access conditions for all market actors. Owning DG/RES generation in their distribution areas might encourage DSOs to favour the connection and operation of their own plants to the detriment of units operated by competing operators that are located in the same distribution area. A conflict may arise between the regulated activity of DSOs and their interests in the generation sector. On the other hand, vertical integration of DSOs and DG/RES production may facilitate the coordination between the distribution activity and the operation of these distributed generators. This may contribute to solving operational problems more efficiently in a distribution network area.

2.1.1 Review of the existing relevant regulation

The level of integration between DSOs and DG/RES generation is subject to the unbundling requirements stipulated by the Electricity Directive 2003/54/EC [12]. Four levels of unbundling can be distinguished: ownership unbundling, legal unbundling, functional unbundling, and unbundling of accounts.

Ownership unbundling is the most far reaching unbundling measure. It constitutes the separation of an undertaking's generation assets from its network assets. Dir. 2003/54/EC stipulates *legal and functional unbundling* for TSOs and DSOs: if the TSO or DSO is part of a vertically integrated undertaking, it shall be independent at least in terms of its legal form, organization and decision making from other activities not relating to transmission (Art. 10 (1)) or, respectively, distribution (Art. 15 (1)). In other words, legal unbundling involves the setting up of a separate network company whereas functional unbundling is a prerequisite in order to ensure the independence of network operators in terms of organization and decision making processes. Functional unbundling encompasses management separation for the day-to-day operation from any other segment of the value chain, independence of management, separation of effective decision making rights, and the adoption of a compliance programme (cf. Art. 10(2), Art. 15 (2)). Furthermore, Dir. 2003/54/EC lays down unbundling of accounts (Art 19). This entails the keeping of separate accounts for transmission and distribution activities as it would be required if these activities were carried out by separate undertakings. For TSOs, the new Directive Proposal [4] envisions a reinforcement of the existing provisions at the transmission level through the implementation of ownership unbundling or the establishment of independent system operators. For DSOs, the unbundling requirements remain unchanged.

Notably, there are three exemptions to the unbundling requirements, all of them directly affecting DSOs. First, at the distribution level, Member States could postpone the implementation of legal unbundling of DSOs until 1 July 2007 (Art. 30(2), Dir. 2003/54/EC)[1]. Second, **small DSOs serving less than 100.000 connections** may be exempted from the unbundling requirements (Art. 15, Dir. 2003/54/EC), i.e., both from legal and functional unbundling [15]. The application of this exemption clause is left to the discretion of the Member States and not limited in time (*ibid*). Last, Art. 17, Dir. 2003/54/EC, allows the existence of **combined operators**, that is, combined TSO/DSOs as long as they belong to the same sector. *Table 1* provides an overview of the existing implementation of unbundling provisions at the distribution and transmission level for the five country cases.

***Table 1*: Unbundling Electricity 2006 [6]**

	Number of TSOs	Number of ownership unbundled TSOs	Number of DSOs	Number of legally unbundled DSOs	Number of DSOs <100.000 customers (100.000 customers exemption applied)
Denmark	1 [1]	1 [1]	107 [107]	110 [107]	103 [100] (N)
Germany	4 [4]	0 [0]	876 [877]	NA	799 [799] (Y)
Netherlands	1 [1]	1 [1]	9 [9]	9 [9]	5 [5] (Y)
Spain	1 [1]	1 [1]	326 [326]	326 [326]	320 [320] (Y)
United Kingdom	1 [1]	1 [1]	18 [18]	18 [18]	4 [4][2] (N)

Both at the transmission and at the distribution level, unbundling has widely been adopted in Denmark, Germany, the Netherlands, Spain, and the United Kingdom. The exemption clause for DSOs serving less than 100.000 connections is applied in Germany, the Netherlands and Spain. This means that in Germany, 799 of 877 DSOs may be exempted from the unbundling requirement; in Spain, 320 of 326 DSOs may be subject to exemption.

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[1] Except for derogations, Member States had to comply with Dir. 2003/54/EC at the national level by 1 July 2004 (Art. 30 (2)). Note that irrespective of the postponement of legal unbundling, functional unbundling of DSOs yet had to be in place.

2 Data in brackets [ ] indicating most recent 2007 data, where available, unless reference to 2005 data is explicitly indicated.

2.1.2 Impact on DG/RES Operator

For a DG/RES operator, non-discriminatory network access and transparent network access charges are pivotal to guarantee equitable access to the essential facility, i.e., the network. Vertical integration of network operators inherently contains incentives to delimit entry of competitors; these incentives decrease with a higher degree of unbundling. For a DG/RES operator facing a vertically integrated network operator, the danger of prohibitive access conditions by means of potentially discriminatorily high connection and/or Use of System charges is particularly pronounced if these charges are not regulated. Due to the asymmetry in information on network impact and cost between the DSO and the DG operator, a lack of transparency in the determination of costs may further aggravate entry, in particular if the charges are subject to negotiation. That is, the impact of vertical structure cannot be seen disentangled from the impact of the regulation.

However, there is also another side of the coin: in the case that a DSO operates DG/RES himself, synergies between the network and the generation segment can be realized in a more efficient manner (see below). In particular for small DSOs falling under the exemption clause, these synergies may be vital to sustain in the market. The (in some cases possibly negligible) danger of vertical foreclosure on a local scale for new small-scale DG generators therefore needs to be weighed against the burden and problems if unbundling is imposed on small vertically integrated DSOs. DSOs above the exemption limit size might be able to achieve the system efficiency benefits of integration operations with DG/RES through arm's length contractual arrangements instead of vertical integration.

2.1.3 Impact on DSO

Several kinds of ownership groups can have different goals for a DSO: a purely financial investor will try to obtain the highest return, whereas other ownership forms as collective or municipal can have DG/RES integration and energy independence as other objectives. This will in particular be the case if local benefits from DG/RES are high, e.g., through collective ownership of RES or lower heating costs due to CHP. The political attitude towards active network management and DG/RES integration can thus differ under different ownership options; however, purely financial investors as owners can lead to a more professional network management and profit from experience from other DSO regions where they operate as well.

The DSO has a crucial position between all distribution network stakeholders. Optimally for DG/RES, it fulfils this coordination role as an active network manager providing communication infrastructure. If a DSO operates DG himself, the location and load integration of DG/RES can be chosen cost-optimally. The potential for network reinforcement delays or replacement by generation capacity can be exploited better in this combination; furthermore, the DSO will integrate DG/RES operation issues into its own point of view and proceed faster from passive to active network management. Using more complex metering and Intelligent Communication Technology (ICT) infrastructure together with the possibility of charging time and/or location dependent use of system charges might also provide sufficient incentives for obtaining cost-optimal allocations.

2.1.4 Regulatory implications

Regulation on provisions governing the unbundling of DSOs has to balance the danger of a vertically integrated DSO exercising local market power (e.g., aggravation of network access for competitors in a rural network) against the financial and operational burden unbundling imposes on small DSOs that have to sustain against large-scale generators in the European electricity market. It may be further subject to discussion whether the exemption clause should be harmonized, or whether it should continue to be to the discretion of Member States.

2.2 Network regulation

The regulation and level of network charges are pivotal for the access conditions of DG/RES generators; this applies in particular to third party access for generators not owning and operating networks themselves. Due to the essential facility characteristics of networks, the regulation of network charges has to be regarded in association with the effective unbundling of incumbent vertically integrated companies. Network charges can be differentiated with respect to connection charges to be paid for obtaining the initial connection to the network, and the network tariff.

The methodology applied for the computation of connection and use of the system charges provides inherently incentives for the DSO to promote or not to promote the connection of new DG/RES generators. Art. 23 (2a) of Dir. 2003/54/EC [12] lays down that it is the responsibility of the regulatory authorities to fix or approve at least the methodologies used to calculate or establish the terms and conditions for connection and access to national networks, including transmission and distribution tariffs. This implies that the methodologies are to the discretion of the individual Member States that have adopted different network regulation regimes. Furthermore, "regulatory authorities shall have the authority to require transmission and distribution system operators, if necessary, to modify the terms and conditions, tariffs, rules, mechanisms and methodologies […] to ensure that they are proportionate and applied in a non-discriminatory manner" (Art. 23 (4), *ibid*).

2.2.1 Network access and connection charges

In most systems, grid codes specify the conditions to be fulfilled in order for the DSO to provide access to the distribution grid to generators seeking their connection to it. However, there may be scope for the DSO to allege that significant difficulties exist which render the approval of the connection of a new DG/RES generator to the grid impossible. The DSO may refuse access where it lacks the necessary capacity (Art. 20 (2), Dir. 2003/54/EC). However, in such an instance duly substantiated reasons must be given as well as relevant information on measures that would be necessary to reinforce the network (*ibid*).

Three major types of connection charges can be distinguished [1]:

- **Deep connection charges**: the DG/RES operator incurs the costs for connection assets and all costs for all necessary network reinforcements, that is, at the distribution and at the transmission level.

- **Shallowish connection charges**: the DG/RES operator has to pay for the costs of connection assets and reinforcements at the distribution level.
- **Shallow connection charges**: the DG/RES operator only incurs the direct costs for connection, and maybe the costs for a new transformer.

2.2.2 Network tariffs

The income of TSOs and DSOs is primarily derived from network tariffs. These are composed of different fees. Depending on their application in national regulation, these fees may comprise energy charges [MWh], capacity charges [MW], reactive power charges [MVAr], Use of System (UoS) charges and connection charges [1].

The type of connection charging philosophy, as outlined above, cannot be regarded in isolation from the network tariff. A DSO may recuperate in the case of shallow(ish) connection charges the reinforcement costs through UoS charges on generators and/or consumers. The simplest kind of UoS charge is a postage stamp tariff, where transmission/distribution charges paid by a certain group of generators/consumers are uniform, i.e., they incur the same charges regardless of their location and time of use. The underlying idea of introducing UoS charge differentiations is that different parties connected to the grid should pay the share of system usage they need. In sum, they represent the DSO's revenue and need to be equivalent to its allowed revenue. This can be implemented by a multitude of different approaches: either both consumers and generators or only consumers can pay UoS charges. Furthermore, UoS charges can vary according to the voltage level each agent is connected to, or according to the location of agents (nodal/zonal pricing).

Finally, different systems have implemented different splits of connection/UoS costs between generators and consumers. Thus, in some systems, both generators and consumers pay part of the grid costs (though normally the fraction paid by consumers is larger), whereas in others only consumers pay.

The network tariff is embedded in the national network regulation regime. Network tariffs must add up, together with connection charges, to the total allowed network revenues of the DSO/TSO. The allowed revenues of the DSO/TSO may be strictly based on the cost incurred by this entity when developing and operating the network. This is known as cost of service regulation. Alternatively, allowed revenues may be based on the expected level of costs that would be incurred by an efficient reference company serving this area. Thus, if the actual costs are below (respectively above) the reference level, part of the difference would be earned (respectively, paid) by the DSO, which therefore is encouraged to cut costs. This is normally referred to as incentive regulation and can refer to capital (investment) costs or operational (losses and some maintenance) costs. This is further elaborated for the case of network losses in section 3 dealing with the analytical representation of the functioning of the system.

2.2.3 Review of the existing relevant regulation

This section provides a review of national network regulation: this encompasses an overview of network regulation, the general application of connection and UoS charges (*Table 2*) as well as the more detailed design of UoS charges (*Table 3*).

Incentive regulation, notably revenue cap, is the predominant network regulation regime in the five country cases. In Germany where cost of service regulation was still applied during the conduction of the country survey, revenue cap incentive regulation is implemented from the beginning of 2009 so that all five countries have either incentive or yardstick (Netherlands) regulation.

***Table 2*: Network regulation, connection and Use of System (UoS) charges (2007)**

	Network regulation	**Connection charges**	**Are connection charges regulated or negotiated?**	**Who pays UoS charges?**
Denmark	Price/Revenue cap	Shallow	Regulated	End consumers, Non-DG generators
Germany	Cost of service	Shallow	Negotiated	End consumers
Netherlands	Yardstick	Shallow below units of 10 MVA, deep for units above 10 MVA	Regulated when below 10 MVA, negotiated above 10 MVA.	Only consumers pay UoS charges: - Large consumers: fixed charge + capacity dependent charge - Small consumers: fixed UoS charge
Spain	Revenue cap	Deep	Negotiated[3]	End Consumers
United Kingdom	Revenue cap	Shallowish	Negotiated	DG/RES pays DUoS, but exemption from TUoS charges. Large-scale power does not pay DUoS charges.

As for connection charges, there is a wide spectrum of approaches adopted by the individual Member States. Both Denmark and Germany apply shallow charges, which are regulated in Denmark and subject to negotiation in Germany. The United Kingdom has implemented a shallowish charging regime in distribution, whereas in transmission generators pay shallow charges. Also in the United Kingdom, connection charges are negotiated. However, only incidentally cases are brought to the regulator. In Spain and in the Netherlands for units above 10 MVA, deep charges are implemented and subject to negotiation in both cases. By contrast, small-scale generation units below 10 MVA incur shallow regulated charges in the Netherlands.

One way for the DSO to recuperate connection costs (in the case of shallow and shallowish charges) is by means of UoS charges. Costs can be socialized, i.e., spread among all network users, or levied

[3] Connection lines, transformers, etc. are built and paid for by DG and then transferred to the DSOs. Further costs of upgrading existing installations to be paid by DG are computed by the DSOs under negotiation.

directly on generators that obtain the connection (see above). The allocation of charges is crucial as it determines which actors pay for the new connection and whether costs are recovered immediately by the DSO (deep charges) or whether they are recuperated over time. Out of the five country cases, only in the United Kingdom and in the Netherlands, DG/RES generators pay UoS charges (*Table 3*). In the United Kingdom, DG/RES producers pay only distribution Use of System (DUoS) charges, but are exempted from transmission Use of System (TUoS) charges. DUoS charges are differentiated with respect to day and night and are related to a mix of drivers (kW and kWh). In the Netherlands, UoS services are split into system services and transport services; consequently, UoS charges consist of system charges and transport charges. DG operators incur UoS charges for system services, but only for the amount of electricity taken from the network. If net off-take in a year is 'negative', no system charges are levied. The charge is kWh based and should cover the costs for reserve requirements, black-out arrangements, costs related to maintaining the power stability, etc. Transport charges are either kW based or both kW and kWh based, dependent of the network level. A DG-operator does not pay transportation costs for the energy supplied to the grid. These charges do not exhibit any form of temporal or locational differentiation. DG generators in Denmark, Germany and Spain do not pay network use charges.

***Table 3*: Application of Use of System charges (2007)**

	Are UoS charges applied for DG?	**How is this charge calculated (system services, transport services)?**	**Differentiation (with respect to location/network voltage level/time of use) or uniform charge?**	**UoS charge level**
Denmark	No, not for most existing DG; new wind and CHP installations can be affected.	/	- TSO customers: TSO postage stamp tariff only - Private customers: DSO + TSO tariff	0.54€/MWh for conventional generators (TSO access), 26,20 €/MWh for private customers (14€/MWh TSO + 12.20 €/MWh DSO; exemplary)
Germany	No, only end consumers pay UoS charges.	/	Voltage level	€/kW and €/kWh
Netherlands	DG operators pay system charges, but only for the amount of electricity taken from the network. End consumers	UoS charges: - system charges (paid by DG) - transport charges (kW or both kW and kWh based, not paid by DG)	Differentiation in voltage level (network) is applied. No differentiation with respect to location or time of use.	The overall system services tariff was 1.17 €/MWh in 2007

	pay UoS charges.			
Spain	No, only end consumers pay UoS charges.	/	Differentiation in voltage level, time of use and the maximum instantaneous power consumed in each period (if ToU applies).	- Annual capacity charges for LV households: 18.16 €/kW - Energy charges for LV households: 0.02 €/kWh
United Kingdom	Yes. DG/RES pays DUoS, but does not pay TUoS charges.	The regulator OFGEM encourages DSOs to make their use-of-system charges more cost-reflective.	DUoS charges are based on pence per kWh, with a differentiation for day and night electricity generation.	Charges are related to a mix of drivers (kW and kWh).

2.2.4 Impact on DG/RES operator

The choice of connection charging approach determines the cost and risk allocation between the DG/RES operator and the DSO. In the case of deep charges, the DSO recuperates the investment costs immediately up front. By contrast, under a shallow charging regime, the DSO gets reimbursed for the costs over time, typically by recovering them via use of system charges.

With regard to connection charges, the DG/RES operators have a clear preference for shallow connection charges. The financial expenses are not only lower than under shallowish or deep connection charges, but risk exposure is decreased as well: when a new generation unit is planned, it is quite uncertain which network reinforcements the TSO and DSO consider necessary under deep connection charges. The same argument applies to shallowish connection charges.

In terms of Use of System charges, DG/RES operators obviously prefer the approach when those are borne by consumers only. UoS charges can consist of annual fixed fees (€/kW) and variable tariffs (€/kWh). It is advantageous if DG/RES are legally defined as generation units only and the few kWh they need themselves, e.g., for communication equipment during times of non-generation, is net metered against their generation. Otherwise, they can face relatively high annual fixed fees as consumers linked to a certain voltage level.

2.2.5 Impact on DSO

In general, a DSO will prefer deep connection charges to recover all costs linked to the connection of a new generation unit. An exemption case can occur if the DSO wants to increase its interest-bearing regulatory asset base, e.g., under cost-plus regulation. Apart from this, a DSO favours the fastest and most extensive cost recuperation method, i.e., deep connection charges. Locational signals for the construction of DG/RES facilities are desirable from a DSO point of view. Besides, they are the simplest way to turn DG/RES beneficial for grid operations. Locational incentives provided by one-time upfront payment have a stronger impact compared to those produced by locational power prices (that is, reflecting temporary network restrictions). One-shot payments provide strong locational signals, whereas those provided by power prices or UoS charges are weaker since these prices cannot be predicted with enough accuracy by generators or promoters at the time when these generators are installed. On the other hand, locational power prices adapt automatically to network and market conditions while one-shot payments may deviate from the actual cost that each generator makes the system incur.

Several network charging options may be considered:

1. Applying deep connection charges to generators. No UoS charges are applied.
2. Applying deep charges only for the fraction of the cost of reinforcements that each generator is deemed to be responsible for. No UoS charges are applied.
3. Applying shallow connection charges and no UoS charge to generators.
4. Applying a combination of shallow connection charges and UoS charges.

When only shallow locationally differentiated connection charges are applied to generators (option 3), the remaining fraction of the cost of the grid that is attributable to generators should be socialized either to generators, to consumers, or to both of them through common uplifts in use of system charges.

A trade off must be achieved between the efficiency in the allocation of grid costs, the computation of locational signals and the incentives provided for promoters to install new DG/RES generation:

1. This option does not provide the right efficiency incentives, since DG/RES generators would have to pay the cost of many network reinforcements that will be used not only by them but also by other agents. Besides, it clearly discourages the installation of new DG/RES generation.
2. This other option provides the right locational signals from a conceptual point of view. By making DG/RES generators responsible for the grid costs they are expected to cause, these charges would encourage promoters to install DG/RES generators where it is most efficient in terms of the total costs incurred by the system. Therefore, if these charges were applied, the DSO would be encouraged to promote the connection of new DG/RES generator to its grid. However, new DG/RES generators would face high entry costs and therefore promoters would not be encouraged to install new generation. One drawback of this option is that the charges paid by DG/RES generators would probably deviate from the actual use these generators end-up making of the grid. Therefore, if these deviations were significant, these charges could be regarded as unfair
3. This option encourages promoters to build new generation but makes the connection of DG/RES generation less attractive to the DSO and less efficient.
4. This is an intermediate situation whereby the resulting locational signals are not as strong as under option 1 (the final payment to be faced by DG/RES generators is not known in advance). Therefore, the location of DG/RES generators may not be as efficient as under option 2.

However, generators would receive a locational signal, based on the estimation of the network usage charges to be faced by them, which is likely to go in the right direction in most cases. As in option 3, entry payments faced by DG/RES generators would be small. However, in this case total payments would be significant.

If DSOs have to pay the cost of the reinforcement caused by DG/RES generators and cannot fully recover it from their customers, they will try to prevent new generators from installing.

2.3 Remuneration of DG/RES

The remuneration of DG/RES operators involves two important aspects: first, many DG/RES technologies are still not competitive in commercial terms compared to conventional generation. Their positive externalities, such as their low emissions impact, contribution to enhancing energy efficiency, diversification of the energy mix and security of supply, etc. have been rationales for the promotion of RES- and CHP-based electricity. Second, the remuneration of the generation within a distribution area may condition the operation profile of the corresponding units. Here, a distinction should be made between RES generation that makes use of primary energy sources that exhibit natural or operational variability[4] and cannot be stored economically for the time being, and the remaining RES/DG generation. The remuneration scheme adopted for each generation technology may encourage generators to produce energy when it is more valuable for the system and provide other type of system services during the remaining time (at least in the case of conventional DG generation or RES generation where primary energy storage is possible). The generation of the first type should probably be used whenever the primary energy source is available and as long as system stability allows it, whereas the operation of the latter type of generation should depend on the existing conditions.

Besides, an efficient remuneration scheme should encourage generation promoters to install new plants where they may be more valuable or necessary. The operation and geographical distribution of DG/RES units may affect the price of energy in the system. They may also affect distribution and transmission congestion and losses, which will in turn have an impact on the amount and nature of network reinforcements to be undertaken.

Directive 2001/77/EC ([11], RES-E Directive) and Directive 2004/8/EC ([13], CHP Directive) lay down that Member States may give direct or indirect support for electricity produced from renewable energy sources or cogeneration based on a useful heat demand, respectively. The choice and level of the support instruments are to the discretion of the Member States. This allows accounting for the state of maturity of the individual technologies and the specific conditions in each Member State. Support schemes can be subdivided into investment support (e.g., capital grants) and operating support. The latter type of support can be distinguished into price-based and quantity-based support schemes. The prevalent price-based support schemes are feed-in tariffs and price premiums. Feed-in tariffs mean that

[4] Wind and photovoltaic constitute examples of energy sources with natural variability, whereas CHP is an example for operational variability when power generation is dictated by heat demand.

DG/RES units receive a fixed tariff per produced kWh for a certain period of time. These tariffs can be differentiated between technologies and other factors as efficiency requirements. By contrast, price premiums are bonus payments per kWh on top of market prices to facilitate market integration of DG/RES. Under quantity-based support schemes, an obligation to have a certain share of DG/RES generation is imposed on utilities, traders or consumers. One possibility are quota systems combined with the setting up of financial markets for tradable green certificates: for the generation of green electricity, a corresponding amount of green certificates is issued that in turn can be traded on the green certificate market. The revenue of DG/RES generators is hence composed of the sum of the electricity price and of the certificate price.

2.3.1 Review of the existing relevant regulation

***Table 4*: Support mechanisms**

	Prevalent support mechanisms
Denmark	Price premium
Germany	Feed-in tariff
Netherlands	Price premium
Spain	Feed-in tariff and price premium
United Kingdom	Quota system with TGCs (Renewable Obligation)

Many of the considered countries have opted for either of 2 energy remuneration schemes: feed in tariffs (FIT) or a system of premiums over the price of energy in the system dispatch (premium). Some exceptions exist, nevertheless. Spain allows promoters to choose between both remuneration systems. Germany has implemented a system of FIT with the exception of CHP generation, which earns the market price plus a premium. The regulation in place in the German system in relation to the remuneration of DG has recently changed but latest changes are not considered in this review. In the Netherlands, DG/RES generators receive a variable premium over the market price. In Denmark, the system applied depends on the generation technology: on-shore wind generators receive a premium, off-shore wind capacity is contracted through a tendering process, CHP generation with biomass receives a feed in premium and photovoltaic generation is subject to a system of net metering. Finally, in the UK a system of green certificates is in place whereby generation companies are forced to produce a certain fraction of their total output from renewable energy sources. RES generators' revenues result from the sale of their green certificates. The information from the own survey has been supplemented through questionnaires answered by parties in the different countries in the context of the SOLID-DER project [8].

Only the system of premiums results in the price of energy earned by DG/RES generators changing according to the value of this energy for the system at each time. However, other countries like Spain have implemented other incentives for generators to produce power when their energy is more valuable for the system. CHP, biomass and waste generators in Spain that opt for a feed-in tariff earn a different regulated price during peak and off-peak hours.

The payments received by RES/DG generators in most of these systems depend on the type of technology considered as well as on the size of the generator. The level of payments to generators of each technology mainly depends on the investment and production costs faced by this type of generators. The objective of regulatory authorities in most systems is to achieve the installation of a predetermined amount of generation capacity from each technology. Therefore, despite of the fact that the operation profile and voltage level of the grid where generators are connected varies from one generation technology to another, differences in payments among generation technologies should not be seen as a form of temporal and voltage level differentiation. In other words, differences in payments to generators across technologies are not directly related to the value that the energy produced by each type of generators has for the system depending on the time when this energy is produced and the voltage level where it is injected into the grid. The remuneration scheme in place in some systems, like the Spanish one, is deemed to encourage DG/RES generators to produce as much energy as they can whenever it is possible.

Prices earned by RES/DG generators in the considered countries do not exhibit any form of geographical differentiation with the exception of Denmark, where different prices may be computed for the two subsystems within the country. Regarding the responsibility for deviations from their program, or expected output, UK generators are not penalised for these deviations, while generators in Denmark receive an average compensation based on the level of the balancing costs they are expected to incur. Generators in Spain and the Netherlands are responsible for the balancing costs they make the system incur (due to deviations from their program).

2.3.2 Impact on DG/RES operator

A Member State's choice of support scheme is the main driver for DG/RES development next to the general level of support. With regard to system integration and incentives to improve integration with the distribution grid, DG/RES revenue could be composed of the following factors in the future:

Revenue = Market price + price premium + ancillary services provision + bonuses

The market price is self-explaining; the price premium is the Member State's main DG/RES promotion instrument. Alternatively, these two factors can be replaced by a FIT. Several bonuses are possible: a system service bonus reflects an additional payment for meeting certain technical standards which are beneficial for the network, e.g., for participation in frequency stability. Such a factor can be defined nationally as part of the remuneration scheme, but it is also possible that the TSO or DSO has a willingness to pay for it if it is beneficial for network operation. Another possible bonus is a dispatch bonus for operating at times when the network situation is constrained or deviates from plans; this also comprises income from ancillary services, such as for participation in balancing markets and offering black upstart capacity. The last income factor could be locational bonuses for placing and operating the DG/RES unit where and when there are network constraints. This formulation draws the attention to two possible implementations: the first possibility is locational power prices which are variable over time, i.e., they are included in the market price and reflect the current system situation. As they depend on demand, other generators and system changes, they are extremely difficult to forecast over a long-term basis and can therefore constitute a high financial risk for DG/RES investors. The second possibility is one-time ahead payments: the DSO could publish a list of beneficial sites, desired generation technologies and capacities. A certain investment grant will be given to the DG/RES operator. For the DG/RES operator, this is risk-free; for the DSO, it corresponds to the opportunity cost if DG/RES is placed randomly. In the subsequent chapter 3, only the bonus transferred as reduced connection charge is assessed because it is expected to create the largest incentive to DG location decisions.

2.3.3 Impact on DSO

The design of the national DG/RES support scheme has a strong impact on the DSO: if the operation of a technology is profitable in the DSO region, numerous units can be installed within a short timeframe (compared to the timeframe of grid expansion). If DG/RES have priority access, the DSO does not have any influence on the location of new facilities. In addition, the DSO can be charged with implementing the support scheme locally, e.g., metering and administering energy amounts and payments locally.

If the DSO is responsible for remuneration by the FIT, it needs to be ensured that this is not mixed with other subjects as grid connection charges etc. The new German FIT ([17], §§ 11, 12) is designed in such a way that newly connected DG/RES units have to receive the FIT, regardless if they can actually produce or if they cannot due to network congestion. Very few DG/RES full load hours in a grid can require high additional capacity investment. With the new flexibility the DSO can decide where the optimal balance between network extension and paying the FIT without receiving any power will be reached (compensation payment). Ideally, the DSO will strengthen the network to a socially optimal point in this respect. A practical problem arising is the question to which extent the DSO's valuation is correct, i.e., to which extent the regulator accepts these compensation payments having an impact on use-of-system charges.

2.3.4 Regulatory implications

The value for the system (and the DSO) of the energy produced by RES/DG generators depends on the time and the place where it is produced. Therefore, energy prices earned by these generators should exhibit some form of temporal and geographical differentiation. Then, non-intermittent, controllable generators would be encouraged to produce energy when the system in general and the DSO in particular can get a higher value from this energy. Besides, promoters could be encouraged to install new RES/DG generation where it is more valuable for the system and the DSO. In order for locationally and temporally differentiated prices not to be perceived by DG/RES as a risk source, annual average prices should be more or less stable. Thus, homogenous prices could be computed for several groups of hours throughout the year. Besides, price zones could be defined priory-based on existing transmission constraints. In addition, DG generators should be allowed to sign long term supply contracts for a fraction of their total production so that they are guaranteed the recovery of their investment after some time.

This would be automatically achieved if prices earned by DG/RES generation were indexed to the market price (a system of premiums were implemented) and market prices internalized the effect of congestion and losses in the dispatch (zonal/nodal energy prices were applied). If prices earned by DG/RES generation are not indexed or in some other way related to the market price, they should at least exhibit some form of temporal differentiation based on the time of the day, and the time of the year, when RES energy is produced. Several blocks of hours could be defined and the price of energy could be computed separately for each of them. Analogously, the remuneration level of these generators could vary from one area of the system to another. In order to achieve this, separate congestion and losses economic signals could be sent to generators.

Generators should face penalties when they deviate from their scheduled program. This would encourage them to improve their prediction systems. In order to further reduce the level of these deviations, they should be allowed to join Virtual Power Plants since their aggregate output would probably be more predictable. Then, the corresponding DSO would have more certainty about the output of these generators and could better program the operation of the distribution grid. In those systems where the DSO is responsible for providing and complying with a program for the net generation/demand within its area, the DSO would incur lower balancing costs. If reducing the deviations in the output of generators of a certain type proves to be very difficult, these generators could receive a compensation corresponding to their expected level of balancing costs.

A comparatively high remuneration of DG/RES can mitigate other barriers, such as high network charges. Both charges and support schemes should therefore be seen as an interdependent system, and major adjustments should only be made with reference to the other factor.

2.4 Market participation of DG/RES

Unbundling of system operators, non-discriminatory network access and sufficiently high remuneration of DG/RES are prerequisites for market entry of DG/RES operators. Another important aspect for the creation of free access for distributed as compared to central generation consists of market participation requirements for DG/RES operators, i.e., the accessibility of wholesale electricity markets for small-scale generators. In particular, this becomes crucial when DG/RES operators are not entitled to support schemes or receive more market-oriented support, such as quota systems with tradable green certificates or price premiums (in contrast to the traditional fixed feed-in tariff, which is typically coupled with priority access). In addition to financial and formal requirements (e.g., solvency, possibly additional collateral, registration, training, appointment of transporting party), there are frequently minimum capacity requirements and specific trading fee regimes generators need to pay. Depending on the market rules in place, the latter two requirements may adversely affect small-scale generators. If they do not meet the minimum capacity requirement, they cannot *de facto* participate in the wholesale market; likewise, high trading fees may impede the entry of small-scale producers.

2.4.1 Review of the existing relevant regulation

Minimum capacity requirements exist in Denmark and Germany, whereas the Netherlands, Spain and the United Kingdom have no such requirements (*Table 5*). In Denmark, the minimum capacity for bidding on the wholesale market amounts to 0.1 MW. In Germany, for participation in the OTC (over-the-counter) trade or on the European Energy Exchange (EEX) generators need to have a size of at least 1 MW.

Concerning trading fees, there are regimes in Denmark and Germany facilitating market access for DG/RES. At the Danish power exchange Nordpool Elspot, direct participants incur an annual fee of 15000€ and a variable trading fee of 0.03 €/MWh (Nord Pool). There is a specific trading regime for small direct participants allowing them to waive the annual fee and pay a higher variable fee of 0.13 €/MWh instead. As for Germany, there is an annual fee for the participation in all products of EEX Power Spot GmbH of 12500€. However, for market participants trading via a designated broker and whose annual trading volume amounts to less than 2.5 m€, the annual fee is reduced to 2500€ [18]. In the other three countries, there are no such specific regimes.

***Table 5*: Wholesale market participation of DG/RES (2007)**

	Are there minimum capacity requirements for bidding on the wholesale market?	**Are there specific trading fee regimes for small-scale generators on the wholesale market?**
Denmark	0.1 MW	Yes. Participants at Nordpool Elspot market can waive the annual fee of 15000 € and pay a higher variable fee of 0.13 €/MWh instead.
Germany	> 1MW (OTC, EEX)	Specific fee
Netherlands	No	No
Spain	No size limitation exists.	n.a.
United Kingdom	No, there is only a license (to supply) requirement for all generation units.	Process of acquiring supply license for wholesale market can be costly, especially for small generators

2.4.2 Impact on DG/RES operator

The participation in power markets is both a chance and a threat for DG/RES operators when compared to a situation with a fixed FIT. It offers the possibility to market the generated electricity directly or indirectly on the wholesale markets. For direct participation, special trading fees for small market actors can be a crucial integration factor. Indirect participation can happen through aggregators such as virtual power plants. Besides positive scale effects for market participation fees, this option includes the possibility of balancing several intermittent energy sources to reduce balancing costs.

Different approaches to encourage market participation from a (former) FIT scheme have been practiced [3]: Denmark (2000-2008) and the Netherlands (2008 onwards) ensure an overall revenue as the sum of the market price and the price premium for certain technologies instead of giving a fixed premium on top of market prices. Temporary opt-out of the FIT, as it is practiced in Germany from 2009 onwards, also aims at a better market integration. Generators can withdraw their units with one months notice from the FIT and return to FIT remuneration with the same notification period. These approaches can be seen as a transition step to a fixed premium or full self-marketing.

Time-variable interaction with other market entities requires the provision of IT infrastructure. DG/RES operators have an interest to install such infrastructure only if they are compensated for it, either through adapted operating support or through higher expected revenues by market participation.

2.4.3 Impact on DSO

The DSO's attitude towards market participation of DG/RES depends on the detailed market design and information flows. If congestion signals are reflected in market prices, the DSO has a clear preference for DG/RES market participation. However, if market participation does hardly affect the DSO except for providing communication infrastructure, it is rather indifferent. The issue of IT communication standards is highly relevant, as can be illustrated by the following example: if the DG/RES operator communicates only with the energy exchange (or its intermediate aggregator) and the TSO for balancing monitoring, the DSO will not be able to adjust its network to the actual generation of the unit. In such a case, the DSO can only react with a time lag. Hence, the possibility for inclusion of the DSO in information chains is important for active network management.

Participation of DG/RES in energy markets may tend to be positive since prices earned by these generators would then vary according to existing conditions in the global system (global balance of demand to available generation capacity), which will most likely resemble those in the DSO area in many cases. Thus, DG would be encouraged to produce in times when demand is high (also in the area), thereby helping to reduce line flows to be managed by the DSO. On the one hand, if the aggregate price earned by DG participating in the market (market price + premium) is too high, these generators will have insufficient incentives to cooperate with DSOs to overcome operation problems. Therefore, market premiums should not be too high. If distributed generators that participate in the market are held responsible for the deviations from their scheduled output, integrating them in the operation of the distribution area will be much easier for DSOs. On the other hand, if the DSO or local retailer is forced to buy all the power produced by DG (DG does not participate in the market) and DSOs are the only ones responsible for maintaining the power balance in the local system, operation of distribution areas where a large amount of DG exists will be much more difficult.

2.4.4 Regulatory implications

Transitory support schemes can facilitate market integration of DG/RES units. Along with this, market participation rules are an important factor: low minimum capacity requirements and special trading fees for small direct participants can encourage direct marketing without the necessity of intermediate institutions. DG should be held responsible for the deviations from their scheduled output sold in the market. However, these generators should be allowed to merge their production with others' and create VPPs or trade units to reduce these deviations.

Participation in the market by DG is positive and should be encouraged so that generators receive economic signals related to the value of their energy for the system in each time. Variable premiums could be used for this. In order for DG not to perceive volatility of prices as a significant risk factor, they should be allowed to sign long term supply contracts for a fraction of their total production so that they are guaranteed the recovery of their investment after some time. Other alternatives are the application of zonal prices with some time differentiation, but not with an hourly resolution.

2.5 Participation in ancillary services

Increasing penetration levels of DG inevitably lead to the question how DG/RES can participate in the provision of ancillary services. Art. 2 (17) of Directive 2003/54/EC defines ancillary services (AS) as "all services necessary for the operation of a transmission or distribution system". A more concrete definition is that AS encompass "all services required by the transmission or distribution system operator to enable them to maintain the integrity and stability of the transmission or distribution system as well as the power quality" [21]. Ancillary services can be distinguished from system services. As for *system services*, they are supplied by a system functionality (e.g., system/network operator) to users connected to the system. *Ancillary services* are acquired by the system operator from system users (generators, loads and system assets) so as to be able to provide system services [21]. Various kinds of AS exist, with partially very different characteristics:

- **Frequency control**: frequency is a global system variable. Three kinds of frequency control can be distinguished:
    - *Primary frequency control* is activated by a deviation in the system frequency and has the aim of establishing a new point of production and demand equilibrium with only a slight deviation from the nominal frequency. It is a local automatic control: all the generators within a synchronous zone that are fitted with a speed governor (or primary control device) perform this control automatically (on the demand side, frequency-sensitive loads, such as induction motors, can participate as well) [34].
    - *Secondary frequency control* is frequently automatic, but can also be manual. Its purpose is to restore the nominal system frequency of 50 Hz and interchanges with neighbouring control areas to the planned values. Thus, the primary frequency control will be fully available again [10].

- *Tertiary frequency control*, also the so-called 15 minute reserve, can be automatic or manual. It encompasses manual changes in the dispatching and commitment of generating units so as to restore primary and secondary frequency control, to manage congestions in the transmission network, and to bring frequency and interchanges back to their set point when secondary control is unable to do the latter [34].

- **Balancing markets:** this is related to the frequency regulation service since its aim is correcting imbalances between generation and demand in the system. The financial responsibility for a part of the regulating power activation (frequency control) is allocated through balancing mechanisms.
- **Voltage control**: voltage control involves the provision of reactive power by generation units in order to keep the voltage in certain nodes within the required limits. In order to provide reactive power, active power output of generators may have to be decreased, thus affecting their market revenues. Therefore, this service must be remunerated. Contrary to what happens in the load frequency regulation service, this service must be provided by units that are located in the same area where voltage problems are likely to arise. Therefore, the number of generators that can provide this service is fairly limited most of the times. Competition in the provision of this service can only take place locally.
- **Black-start capability:** this involves providing the required amount of power and voltage support for the system in an area to be able to return to normal operation after having interrupted service because of an emergency that, otherwise, could have affected the integrity of the system. This service can only be provided by units that are able to operate in an autonomous way.
- **Island operation:** in the future it would be very useful if DG could supply local load when their area needs to be disconnected from the rest of the system for emergency reasons. This would avoid service interruptions when the system as a whole runs into trouble and load shedding is required.
- **Solution of network constraints:** this can be considered a type of congestion management service. Generators whose power output is affecting, or may affect, the flow through a congested line, may change their output so that the flow over this line is kept within the technical limits. The provision of this service is normally associated with the existence of a system of re-dispatch to manage congestion. If this is not the case, the solution of network constraints is generally managed through the process of allocation of scarce transmission capacity either in the energy market or as a separate one. Only the congestion that arises after the energy market takes place would be solved according to the aforementioned mechanism.

The role of DG/RES generators in the provision of ancillary services could include the participation in congestion management schemes, the reduction of distribution and transmission losses, the participation of these generators in the load following and the balancing services, the regulation of the reactive power they produce and that of the voltage in certain nodes. The provision potential of a kind of ancillary service depends on the DG/RES technology and its operation patterns.

Ancillary services can be provided through several kinds of agreements or markets [35]:

- Generators can be obliged to deliver them just by being connected to the grid, e.g., for basic voltage control.
- The responsible system operator can buy them through bilateral contracts.
- The system operator can tender necessary ancillary services over longer periods.
- The system operator can buy them short-term at a spot market.

In order to get generators to participate in the provision of these services, a system of regulated payments could be implemented in order to encourage, for example, RES/DG generators to keep their load factor within certain limits or to comply with certain requirements. Alternatively, the DSO could enter into ad-hoc contracts with these generators for them to provide system services. One last option involves allowing them to participate in the corresponding markets (assuming these markets exist).

Different transaction types are possible for different kinds of ancillary services. Minimum bid sizes (e.g., in MW) and higher transaction costs can be an obstacle for DG/RES participation.

Nevertheless, it would allow the DSO to count on these generators as an additional source of flexibility in the operation of the system, which may be more or less expensive depending on the particular generation type and technology but may become economical under certain conditions.

The estimated impact of ancillary services (AS) revenues on DG revenue stream may depend on the ratio of prices earned for participation in AS to energy prices earned by DG. Normally, this impact tends to be rather incremental. The technical and market design will affect the potential of DG to contribute to the provision of AS. In general, DG needs to be controllable to participate in AS. Besides, the required communication infrastructure and protocols must be in place for DSOs/TSOs to interact with DG. Market design should encourage DG to participate in the provision of these services by allowing them to receive an adequate remuneration. Support schemes associated with the production of power by DG/RES should be based on the social value that this energy has. Incentives for DSO to integrate DG in the provision of these services should also exist.

2.5.1 Review of the existing relevant regulation

In order to provide these services, DG/RES generators have to comply with certain requirements that vary across countries. DG/RES generators in Spain must be controllable, send an offer that is larger than 10MW and sell their energy in the market or through contracts to provide AS. Generators in the Netherlands must be larger than 5 MW (though aggregation of units of the same type is allowed), and be connected to a voltage level that is 1 kV or higher. Large generators in Denmark can participate in the balancing service. In order to provide this service, generators in Germany must submit an energy offer that is larger than 15MW, though aggregation in Virtual Power Plants (VPPs) is possible.

Services that can be provided by these generators in Spain include the balancing service, the load following one, the management of restrictions and the contribution to the system security of supply. Generators in the Netherlands can participate in several ancillary services, however, in practice, they do not make any contribution. An exception is CHP generation, which provides regulation reserves and participates in the balancing service. CHP in Denmark can participate in the balancing service, and islanding has only been implemented in pilot projects. DG in Germany can participate in the balancing market through the aggregation of the output of several units in VPPs. Moreover, there are plans to require these units to have fault ride through capability.

***Table 6*: Participation of DG/RES in Ancillary Services (2007)**

	Does DG provide ancillary services (e.g., energy for losses, reactive power)?	**Have AS markets run by DSOs been created in your system?**	**Does the DG operator have direct access to the balancing market, i.e., to submit bids?**
Denmark	No	No	Possible for units >11kW in blocks of >10MW
Germany	Yes	No	No
Netherlands	- Only units larger than 5 MW and connected to the 1 kV voltage network or higher can provide ancillary services - For these qualified units: in principle yes, in practice no	No	- Balancing market: indirect participation through commercial aggregators for distributed CHP operators (horticulture CHP operators) - Market for reserve power: large industrial CHP as well as large industrial interruptible demand
Spain	- Access for controllable RES/DG generators with capacity ≤ 10MW (aggregation of smaller units possible) - "Special Regime" (CHP and RES below 50MW): incentive provided to keep power factor between certain regulated ranges	No	- They can access regulation markets if they comply with the requirements stated to the left
United Kingdom	- DG can arrange with the DSO AS procurement - In practice, aggregated small DG can provide reserves. Bilateral agreements are likely to continue to be used in developing the ancillary service market in the short to medium term.	No	- In theory yes, but in practice the risks associated with operating in the balancing market are too large for singe operators. Therefore small operators tend to contract out to aggregators.

DG/RES generators in Spain that comply with the criteria outlined above can participate in the existing ancillary services markets as any conventional generator. These markets are managed by the TSO. DSOs do not have the possibility to control the output of these generators. Neither the TSO nor DSOs can sign contracts with DG/RES generators for them to provide system services. DG/RES generators in the Netherlands can participate in AS markets (balancing market and reserve market). Generators in the UK and Denmark can either participate in certain AS markets (the balancing market in Denmark) or enter into contracts with the DSO. Therefore, DSOs in these systems have more control over the operation of these generators than Spanish or Dutch ones. Finally, DG/RES generators in Germany that qualify for this service can participate in the balancing market. Organized ancillary services markets run by the DSO do not exist in any of the considered markets. At most, DSOs are allowed to sign ad-hoc bilateral contracts with DG to provide these services. The information from the own survey has been supplemented through questionnaires answered by parties in the different countries in the context of the SOLID-DER project [8].

2.5.2 Impact on DG/RES operator

A DG/RES generator can benefit from the participation in ancillary markets if remuneration is sufficient. However, establishing compulsory AS provision for DG that is not remunerated, like the provision of primary load frequency control, could erode the revenues of these generators resulting from the sale of power in the market or directly to the TSO/DSO. One must bear in mind that in order to provide most of these services distributed generators need to reduce their power output. Integration and controllability of ancillary services from DG/RES would substantially contribute to the operations of a pro-active DSO. Thus, if DSOs begin to implement active network management (ANM) techniques, they will be encouraged to get DG into becoming partially controllable. Controllability by the TSO/DSO would result in this entity facilitating the grid connection and operation of DG. Significant expenses would also have to be borne by DG in order to become eligible for AS provision (control and communications equipment, system of regulation of their output, etc.). These expenses should be taken into account when computing the remuneration of DG for participation in AS.

2.5.3 Impact on DSO

The participation of DG/RES in AS can be highly beneficial for a DSO: system reserves from conventional resources can be smaller if dispersed generation units are allowed to provide this reserve and they are capable of doing so. Most local voltage problems could be solved through active cooperation of DG in voltage control services. A pro-active DSO will take over responsibilities of system stability from the TSO and can thus extend its responsibilities.

The potential impact on the DSO will be larger the more controllable DG is. Thus, DSOs that implement ANM techniques will benefit more from the participation of DG/RES in local services than those DSOs that operate their grid in a passive way. Both organised and bilateral markets should be created to create more flexibility for DSOs and generators to meet and agree on the conditions of the provision of these services by the latter. Services of a local nature, like the solution of voltage problems in each area, should be left to the discretion of DSOs.

2.5.4 Regulatory implications

DG/RES generators should be allowed to participate in the provision of AS if they are capable of doing so. In order to allow them to participate, requirements should be as flexible as possible. Aggregation of units into VPPS should be allowed so that they become part of observable units whose output is more controllable.

The participation of DG/RES and other generators in AS should be encouraged through the application of prices for the provision of these services that are in accordance with the value that the latter have for the system. Creating AS markets and allowing DG/RES generators to participate in them is the preferred mechanism to compute efficient prices for these services. Allowing the DSO to sign contracts with DG/RES generators may be advisable in situations where the number of generators that can provide a certain service is small (for example, the control of the voltage of a specific node). Setting regulated payments is not efficient in general since getting right the price for these services may be very difficult. However, this option must be considered when market power exists in the provision of a certain service.

ANM techniques should be implemented and both organised, and bilateral markets should be created to create more flexibility for DSOs and generators to meet and agree on the conditions of the provision of these services by the latter. Services of a local nature, like the solution of voltage problems in each area, should be left in the hands of DSOs.

2.6 Allocation of costs arising from DG/RES integration

Costs borne by DSOs are affected by the existence of DG/RES generation. Therefore, the impact of DG on these costs should be somehow taken into account when computing the allowed remuneration of DSOs. It is the task of regulatory authorities to monitor that "the terms, conditions and tariffs for connecting new producers of electricity to guarantee that these are objective, transparent and non-discriminatory, in particular taking full account of the costs and benefits of the various renewable energy sources technologies, distributed generation and combined heat and power" ([12], Art. 23f).

Two different situations may occur:

- For low penetration levels of DG, investment and operation costs of DSOs, as well as the cost of losses, tend to decrease as a result of the integration of this generation. An exception to this rule may be the cost of the connection infrastructure needed for new DG generators.
- For high penetration DG levels, the cost of investments, operation and losses may increase (or decrease) as a result of the integration of this generation, with respect to the situation with no DG.

The costs in both situations are highly dependent on the specific type of DG technology (controllability) and the network configuration. A given network might accommodate much higher penetration of certain technologies than other technologies before costs start to increase.

The remuneration of the DSO in Denmark and the UK takes into account the network infrastructure costs caused by the connection of DG/RES. Investments caused by DG must be approved by the regulator in order for the corresponding costs to be included in the reference cost (allowed revenue) it computes. The UK regulator takes into account these costs when periodically updating the remuneration of DSOs (the reference level of costs). Besides, there are other incentives in the UK for the DSO to promote the installation of DG/RES, like the inclusion of investments in the Innovation Funding Incentive scheme if they are aimed at increasing the efficiency in the operation of the network to allow more DG/RES to be integrated. If a distribution area is declared a Registered Power Zone, then additional incentives for the connection of DG/RES apply. For the computation of the remuneration of DSOs, two approaches are possible: either DG related costs are estimated in advance and included in the allowed DSO remuneration under an incentive based mechanism; or the costs incurred and declared by the DSO that are related to DG are included in the regulated remuneration of this entity, thus applying cost based regulation.

In order to encourage the DSOs to facilitate the integration of DG/RES, increases in network/losses costs caused by DG should result in the same increase in the allowed remuneration of the DSO. On the other hand, the DSO should be allowed to retain part of the benefits (reductions in costs) yielded by the existence of DG.

2.6.1 Review of the existing relevant regulation

Regarding the compensation to DG operators for the benefits they cause the system, most of the considered systems do not include any compensation in the regulatory schemes. This is the case of Germany and the Netherlands. In Denmark, these compensations could be agreed bilaterally between the operator and the DSO, though no compensation is guaranteed in advance. In Spain, consideration of these benefits is not explicit. However, for lower levels of DG penetration, the generation is credited some potential for costs reduction and their incentives for production (premiums) are set higher. Finally, in the UK, no rule states that DG should be compensated, but the regulator recommends that DSOs charge generators cost reflective tariffs that, therefore, take into account the benefits that the latter provide to the system.

Nevertheless, the remuneration of these companies in Germany and Spain does not take into account these costs. Yet, in the near-term future, DSOs' revenues in both countries are expected to include them. Remuneration of Opex and Capex in Spain is computed using a formula that determines the reference level for these costs (incentive regulation). This formula is going to be replaced by the use of a network reference model which will also consider the impact on the reference grid development of the installation of new generators. The allowed DSOs' revenues in Germany are based on the costs incurred by the DSO. Therefore, no incentive to reduce costs is provided. However, efficiency incentives will soon be introduced.

Table 7: **Allocation of DG-related costs and benefits (2007)**

	Is the DG operator compensated for benefits the DSO has from connecting DG to the grid?	**Is the impact on network costs, losses and quality of service taken into account when computing the remuneration of DSOs?**
Denmark	No - could be agreed bilaterally	Network costs: Necessary new investments for DG lead to a higher revenue cap; Losses, quality of service: no
Germany	No	Yes, but not explicitly (only included in other cost factors)
Netherlands	No	No
Spain	- In general no consideration - FITs and premiums are generally set higher the smaller DG is, as a means of acknowledging better integration with demand[5]	No
United Kingdom	No. The regulator more passively encourages DNOs to charge DG operators more cost reflective DUoS charges, thereby giving any advantages due to DG back to the operator contributing to this.	- Explicit recognition of DG in periodic regulatory review of the DNOs - Additional incentives for DG deployment: • Innovation Funding Incentive (IFI) • Registered Power Zones (RPZ)

Remuneration of DSOs in the Netherlands results from a benchmarking process (incentive regulation). As it will be explained in section 5, the allowed level of remuneration includes the cost of network reinforcements caused by the connection of large DG, which has to pay them (deep connection charges). However, DSOs' revenues do not include the cost of reinforcements caused by small DG, which only have to pay the connection infrastructure. Only the cost of those network investments caused by small generators that involve the replacement of an old line could be recovered through the revenues related to the depreciation of existing assets. Regulation in the Netherlands considers the possibility of extraordinary network reinforcements in general. Large network reinforcements caused by DG/RES generators are thought to be included in this part of regulation, but funds for financing these reinforcements have not been granted yet.

The impact of DG/RES generation on distribution losses is not considered in any of these countries when computing the corresponding revenues to be earned by DSOs. All the countries, but Germany, compute a reference amount of losses that DSOs are compensated for. Therefore, DSOs in these countries have an incentive to reduce losses as much as possible. The reference level of losses is computed according to the following methods:

[5] It is supposed that small DG connects to lower voltage levels and closer to demand, thus producing lower losses, investment deferral, better voltage profile, etc.

- In Spain, standard loss factors are used. These do not depend on the existence of DG. Differences between real losses and standard ones must be purchased at the pool although in the future, they will have to be paid by the DSO at the average price of energy.
- In the Netherlands, the reference level is computed through a benchmarking process, which cannot take into account the actual amount of DG in the considered area.
- In the UK, the reference level is computed based on the historical amount of losses in each area. However, the amount of DG is likely to have significantly changed recently.
- In Denmark, the reference level does not take into account the existence of DG, but the existence of DG affects the market energy price level which is considered to compute the allowed remuneration.

In Germany, the DSOs are not encouraged to reduce losses and their remuneration is not affected by the existence of DG. The information from the own survey has been supplemented through questionnaires answered by parties in countries in the context of the SOLID-DER project [8].

Previously, the Netherlands had implemented a rule that passed-through the general beneficial effect of DG on network losses. DG generators were paid a small compensation fee. However, a court ruling later deemed this part of regulation as insufficiently founded in current Dutch electricity law and the regulation was removed. No new initiatives have been taken up by the regulatory authority since.

2.6.2 Impact on DG/RES operator

The impact on DG/RES of allowing them to keep some of the benefits they produce is obvious. This would encourage them to install more power. However, not all the benefits resulting from integration of DG/RES should be kept by DG operators. Otherwise, DSOs will not be encouraged to facilitate their connection and integration in system operation. Thus, DSOs should also keep part of these extra revenues. Due to the fact that benefits for the system generally depend on the zone where the DG is located, this mechanism would act as a locational signal to new DG that would help increase their contribution to the efficiency in the operation of the system. Those areas where the system would benefit to a larger extent from the existence of DG would also be the ones where revenues for DG are larger. Hence, the interest of DG promoters would be in line with that of the system as a whole.

2.6.3 Impact on DSO

The impact of DG/RES generation on the DSO costs must be taken into account to compute its allowed remuneration. In order to encourage DSOs to reduce costs (increase their efficiency), a reference level of costs should be computed. Allowed revenues should be equal to the reference costs. Any difference between these allowed revenues and actual costs should be kept by the DSO. The reference level of costs should be adapted to the specific situation of the distribution area served by the DSO. Therefore, a network reference model, which is able to compute the level of costs that would be incurred by an efficient DSO in the same area, should be employed to compute the allowed revenues of DSOs. This model could estimate reasonable CAPEX, OPEX and losses costs. It is important that the DSO still finds it attractive to connect and integrate new DG. Therefore, cost increases/decreases brought about by DG/RES generation should be considered in the following manner:

- Increases in costs due to DG/RES generation should result in the same increase in DSO revenues.
- However, reductions in costs caused by DG/RES should result in a reduction of DSO's revenues that is smaller than the former one. Therefore, DSOs should benefit from the efficiency increases caused by the integration of DG.

2.6.4 Regulatory implications

Part of the recommendations have already been given, or at least outlined, in the two previous subsections (2.6.3 and 2.6.4). Therefore, we shall comment on them here. Regulatory authorities should implement a system whereby both DSOs and DG keep some of the benefits brought about by the installation and the integration into the operation of DG/RES. This system could have the features described in section 2.6.4. Cost increases/decreases brought about by DG/RES generation should be considered in the following manner:

- Increases in distribution network costs due to DG/RES generation should result in the same increase in DSO allowed revenues.
- However, reductions in costs caused by DG/RES should result in a reduction of DSO's revenues that is smaller than the former one. Therefore, DSOs should benefit from the efficiency increases caused by the integration of DG.

In order for revenues related to the increase in the social benefit produced by DG to represent powerful locational signals for these generators, total revenues from DG should not be socialized to all distributed generators in the system. Instead, prices earned by DG in each area, or benefits obtained by DG in each area should be specific to the area.

2.7 Planning of grid expansion with regard to DG/RES

DG/RES generation may allow DSOs to deter or even avoid undertaking certain reinforcements to the grid. In order for this to come true, two main options exist:

- Either DSOs are allowed to own DG that they can control and use in order to avoid or delay network expansions, or
- DSOs are allowed to sign contracts with controllable, non-intermittent DG/RES generators that enable the former to have some control over the output of the latter. Besides, a complete set of other active network management techniques would have to be implemented.

DG could help to solve overload or voltage regulation problems that otherwise would require building network reinforcements that may end up being much more costly than the cost of regulating the output of generators at specific times.

If DSOs receive part of the reduction in network investment costs caused by the installation and subsequent operation of DG/RES generation, the former would be encouraged to promote the installation of generators and plan the expansion of the grid taking them into account. Implementing a system of economic incentives to the DSO is necessary in this respect.

2.7.1 Review of the existing relevant regulation

Central elements of EU legislation are that possible positive effects of demand-side coordination or DG integration need to be taken into account when planning investments ([12], Art. 14(7)). The role of distributed energy is also mentioned in the context of security of supply and infrastructure investment ([14], Art. 3(3)).

In order for DG to be able to deter or delay possible future network investments, it is necessary for the DSOs to make sure that DG will be producing/not producing when it is required by the system. Thus, some level of controllability of the output of DG by DSOs is necessary. DSOs in Denmark and the UK can sign contracts with DG/RES generators. This allows the former to partially control the output of the latter. Regulation in other countries does not consider this possibility.

The remuneration of DSOs in all the considered countries but Germany provides incentives for them to cut costs through the use of some form of revenue cap regulation (2007 status). In Spain, a formula is applied to compute the revenue cap, while in the Netherlands, a benchmarking process is conducted for this purpose. The remuneration obtained by the DSOs in the UK for the new network augmentations is the result of a negotiation process between each of these companies and the regulator. The remuneration scheme to be applied in Germany in the future will provide efficiency incentives. Thus, if DSOs in almost all these countries can control, to some extent, the output of generators, they will use this as a mean to reduce investment needs in the system network.

Active network management techniques have not been implemented in any of these countries. In addition, as explained in section 4, the cost increase/reduction caused by DG/RES generation is not correctly computed in most systems (all but, maybe, Denmark and the UK). Even where DG costs are considered, it is no clear whether the method employed to compute them is efficient.

As a result of all this, DSOs in most countries do not consider the possibility of avoiding network reinforcements because of the presence of DG. Moreover, there are some countries, like the Netherlands, where DSOs have traditionally considered DG to be a potential source of problems. An exception to this rule is the UK, where DSOs seem to be encouraged to take DG into account in the planning process. DSOs in Denmark should also take them into account although most DG is installed in remote rural sparsely populated areas, where its potential to avoid network reinforcements is very small.

Given the lack of incentives for DG in some countries, like the Netherlands and Spain, to provide any kind of service to the system, DSOs tend not to consider DG as a potential resource to solve network expansion problems. The information from the own survey has been supplemented through questionnaires answered by parties in countries in the context of the SOLID-DER project [8].

2.7.2 Impact on DG/RES

DG could be encouraged to cooperate with DSOs in order to reduce flows and solve network operation problems by receiving at least part of the value for the system of the services they provide. In this case, DSOs would be encouraged to take them into account when planning the expansion of the grid. Getting the permission to connect to the grid and to start operation would be much easier for DG/RES promoters.

However, energy market revenues of DG/RES could be negatively impacted by cooperation with the DSO, since instructions by the DSO, or the requirement to be available to follow these instructions, would most probably condition the operation of these units. This impact would probably be not so significant, since, in many cases, when following the instructions of the DSO, DG/RES would be compelled to produce extra power when the generation margin over demand in the whole system is tight. In other words, DG would be told to increase production when prices are higher. Provision of regulation reserves by DG could have a larger impact, since these would limit the production by DG. Therefore, DG should only provide these reserves when other potential sources of these reserves are not available.

2.7.3 Impact on DSOs

Allowing the integration of DG/RES in the network planning process conducted by DSOs would allow DSOs to reduce the network investment costs incurred. If DSOs were allowed to retain part of the benefits corresponding to the reduction in network expansion costs, they would be encouraged to enter into some kind of agreements with DG/RES units. However, in order for DG to be integrated into network expansion planning, these generators should be controllable by DSOs. Thus, ANM techniques should be implemented. The paradigm of operation of the grid by DSOs should move from the traditional passive approach to an active one. This would require a large amount of investments and a change in the operation practices, which would represent a significant cost for DSOs.

2.7.4 Regulatory recommendations

In order to allow DG to positively affect network development costs, this generation must become, at least, partially controllable by the DSO. Therefore, besides the participation of DG/RES generators in other kind of markets, DSOs should have the possibility to sign contracts with them so that the distribution company can ask them to increase or decrease their production when the system needs it. The impact of DG on system expansion cost will be higher the higher the level of controllability of the network by the DSO is. Additionally, in those systems where integration between the DSO and DG has proved (or is deemed) not to cause discrimination problems, DSOs should allow to own DG whose output it can control according to the system needs.

The remuneration scheme of DSOs must provide them with incentives to reduce network expansion costs. We recommend the use of network reference models to guide the computation by the regulator of the regulated revenues of distribution companies. As discussed in section 4, these models, or any other tool or method used to compute DSOs' remuneration level, should take into account the increase or decrease in the network costs caused by DG, but should allow DSOs to appropriate part of the reduction in costs related to the presence and efficient operation of these generators.

2.8 Impact of DG/RES generation on the quality of service

The quality of service level in a system can be computed in terms of the number and duration of interruptions of electricity supply both over the whole system (average levels) and for each consumer. DG may be a source of flexibility in the operation of the system employed by DSOs to improve quality of service levels. However, if DG does not cooperate with the DSO and TSO, they may become a source of problems for the system.

In order for DG to contribute to improving the quality of service a number of conditions must be fulfilled:

- Regulation should encourage the DSO to adapt quality of service levels to consumer demand, i.e., willingness to pay.
- DG must be controllable.
- The level of control of DSOs over DG must be high enough.
- Providing AS must be an attractive option for, at least, part of these generators.

Having distributed generators contribute to increase the quality of service is costly both in terms of required technology changes (DG controllability), and in terms of the decrease in operation efficiency resulting from the change in the operation profile of these generators (that would no longer operate at their nominal rate). Therefore, benefits from their participation in AS markets and other services to increase quality of service should be weighed against these costs.

2.8.1 Review of the existing relevant regulation

The Netherlands, Denmark, the UK and Spain have implemented incentives for the DSO to increase the quality of service. In the Netherlands, the remuneration of DSOs may vary by up to 10% depending on the level of service quality delivered (+-5% with respect to the reference remuneration level). Also, DSOs must compensate those consumers who experience service interruptions. In Denmark incentives associated with the quality of service have been used for almost 1 year. The reference quality of service level is determined through a benchmarking process. In the UK, a reference level is computed as well. If the DSO delivers a higher quality level it gets some extra payments. If the quality level is below the standard it faces penalties. Since the approval of piece of legislation RD 222/2008, the regulation in place in Spain is quite similar to that applied in the UK. Germany has not implemented yet quality of service incentives, but soon quality targets will be established and penalties for not complying with them applied (a system similar to the Spanish one).

However, DSOs in the Netherlands, Germany and Spain do not regard DG as an alternative to improve the quality of service, but rather as a potential source of problems. This may be related to the fact that the level of controllability of DG by DSOs in these countries is very small because the latter cannot sign contracts with these generators. On the other hand, DSOs in Denmark and the UK have the possibility of signing ad-hoc contracts with generators. Despite this, Danish DSOs believe that the potential impact of DG on quality of service levels is only marginal, since they are located in areas where load density is rather low. One additional obstacle to DG significantly contributing to improve the quality of service lies in the fact that in some systems like the Spanish or the Dutch ones, energy prices earned by these generators are so high that their single objective is producing as much power as possible, regardless of the system conditions. The information from the own survey has been supplemented through questionnaires answered by parties in the different countries in the context of the SOLID-DER project [8].

2.8.2 Impact on DSOs and DG

Probably, if part of the potential benefits brought about by DG in terms of quality of service were considered in DSOs' revenues, they would consider the possibility of connecting more DG and interacting with it in order to reduce supply interruptions. Implementing DG controllability and realizing the potential for increase in quality of service would probably require using ANM techniques. DG/RES could also keep part of the benefits caused by their contribution to quality of service levels for themselves. The analysis is quite similar to that conducted under subsection 2.7.

2.8.3 Regulatory implications

Quality of service targets must be set for the distribution activity. Additionally, in order for the DSOs to aim to improve the existing quality levels, both bonuses and penalties should be applied depending on whether the current level is above or below the predetermined target.

Unless existing storage capacity allows the system not to waste available renewable primary energy, intermittent technologies like wind or solar, should be encouraged to produce as much as possible as long as there are other ways to keep quality of service levels within the prescribed limits. Only if emergency situations should these generators be forced to comply with TSO/DSO instructions. Conventional DG generation could be controlled by the operator or contribute to the provision of AS on a more regular basis.

Regulation should allow DSOs to sign contracts with generators so that the former can regulate the output of the latter whenever it is truly necessary for the system. This may change the perception of distribution companies about the potential contribution of DG to improve quality levels. Additionally, the implementation of active network management techniques by DSOs should be rewarded somehow.

Finally, prices earned by DG for the energy they produce and those earned for participating in AS markets should be efficiently computed so that they correspond to the true value that each of these services has for the system. However, in "force majeure" situations, DG should be forced to comply with the requests made by the DSO so as to preserve the safe and reliable functioning of the system.

2.9 Incentives for innovation

Some major benefits that the system (and the DSO) can obtain from the installation of DG cannot materialise unless active network management techniques are implemented by DSOs. This requires investing heavily in innovation. However, innovation investments tend to be large in scale and risky, which makes it difficult for DSOs to undertake them under present conditions.

Therefore, DSOs should be provided with incentives for introducing innovative planning and operation procedures. These incentives may be of three types:

- Innovation expenditures by DSOs may be reimbursed. Other measures could be taken so that risk premiums paid by investors in innovative projects are reduced.
- The regulator or in general government funded agencies may cooperate with the DSOs in the design and implementation of innovative processes.
- Strengthening those efficiency incentives that are related to those parameters that can only improve through investments in innovation.

The largest share of innovation investments is expected to benefit DG/RES integration because they need the development to a pro-active network operator providing more communication infrastructure. Distribution system operations have been rather constant during the last decades and DSOs are expected to cope better with new challenges if they approach them actively, i.e., through innovation projects.

2.9.1 Review of the existing relevant regulation

Incentives for innovation vary across countries. In Spain, the Netherlands, Denmark and the UK DSOs are encouraged to cut costs. Innovation investments may result in cost reductions in the long term future, but these are uncertain. The short term impact of innovation investments in the balance sheet of these companies is likely to be negative, since investments of this type tend to be large. On the other hand, quality of service incentives applied in those systems should encourage DSOs to invest in order to improve quality indexes.

The Spanish regulator has bowed to strengthen incentives to undertake efficient investments, reduce losses and increase quality levels. The present situation in the Netherlands is similar to that in Spain. Even more, due to the system of yardstick competition in place there to determine the remuneration of DSOs, these are discouraged to undertake innovations that can be replicated by the remaining companies causing a reduction in the reference level of costs incurred by these companies. Parties in Denmark are in favour of allowing DG to participate in balancing markets so that DSOs have a larger incentive to integrate this generation. In the UK economic support is granted to those DSOs that invest in the improvement of grid expansion, operation and maintenance processes (IFI support scheme). There are also incentives for facilitating the connection of DG/RES generators.

Finally, Germany is an exception to the general rule, since no incentives have been implemented yet. Also, there is the belief that incentives to innovation would only favour the integration of large DG. Smaller ones would have to be aggregated in order to become units that can contribute to improving the functioning of the system.

2.9.2 Impact on DSO/DG

Innovation would allow the application of ANM, which would be beneficial to both DSOs and DG/RES operators if they are allowed to keep part of the benefits brought about by a more efficient proactive operation of the system grid. Costs incurred by DSOs (mainly) and by DG when devising more advanced solutions for cooperation would be high. In order to reduce them, applying incentives would be necessary. These incentives would reduce the risk perceived by DG and DSOs when undertaking investment in innovation. Besides, they would allow them to reduce the expected cost of innovating.

2.9.3 Regulatory implications

In general, innovations are expected to support the development of a conventional, “passive” DSO to an “active” DSO considerably. This would benefit DG/RES integration. Innovation incentives could be associated with the reduction of grid expansion and operation costs (energy price and losses) and the increase of service quality levels. Since these investments are large and risky, the regulator should provide financial support in the first stages of the innovation process until the benefits resulting from the introduction of these innovations become clear. This support could adopt the form of research funds granted by the government for companies to develop innovative proposals.

The level of controllability of DG by DSOs should be increased and the contribution of the former to AS should be allowed as long as it is feasible. This must make the integration of DG more attractive to DSOs, provided distribution companies seek to improve the functioning of the system through investments in innovation.

Finally, the remuneration scheme of DSOs should provide them with incentives to reduce losses, increase quality levels and reduce investment capital costs through the control of these distributed generators. Besides, cost cuts achieved through innovation should not immediately result in a decrease of allowed DSOs’ revenues. Therefore, the reference level of DSOs’ revenues should not be updated, to take into account cost reductions brought about by innovation, until some time (several years) have passed from the implementation of these innovative solutions.

3. Revenue stream model

DG operators are usually subsidised, and DSOs are widely regulated. These are major characteristics that impact the underlying incentives for the market behaviour of DG generators and DSOs. Interactions between support schemes, network revenue regulation and regulation of connection charges/UoS charges affect the choices of DG and DSO both in their short term optimisation and in their longer term investment decisions. It is very important to secure that the incentive effects of these three regulation elements do not counteract each other.

A revenue stream model that takes all these interrelated elements into account would be very complex. The focus in this chapter has been put on emphasising the important links that exist, based on assessing the individual revenue stream components regarding their importance and their most likely net contribution. Analysing these interactions should enable to investigate if there are ways to secure that the right incentives are passed to the DG and DSO investors to minimise the combined costs elements. If the regulation has different properties for allowing the incentives to be passed, the most efficient regulation should be identified.

3.1 Background

As pointed out earlier, liberalisation entails the unbundling of traditionally vertically integrated undertakings and the introduction of competition in electricity generation and supply (Directive 2003/54/EC). Notwithstanding the opening up of markets to third parties, certain areas continue to be subject to regulation. First, networks for the transmission and distribution of power have natural monopoly characteristics. A natural monopoly exists[6] when the firm's costs are sub-additive, i.e., when it is less costly to supply output with a single firm rather than splitting up production between several competing firms, and when there are economies of scale over some range of production [28]. Networks exhibit the attributes of essential facilities: they cannot be replicated by any reasonable means by competitors, and access to the facility is indispensable [42] for market entry. For these reasons, also in liberalised markets, the income of network companies remains regulated. In the EU Member States, the predominant regulatory approaches comprise cost-of-service regulation, revenue/price cap incentive regulation and yardstick regulation. Second, certain generation technologies, such as those deploying renewable energy sources, contribute to the reduction of greenhouse gas emissions and to the enhancement security of supply. Due to the high investment cost associated with RES-E installations and the fact that externalities are not captured by the market, fossil fuels are at an artificial advantage. This has been a rationale for encouraging the application of support schemes in the generation segment so as to promote electricity produced from renewable energy sources (Directive 2001/77/EC) and combined heat and power (Directive 2004/8/EC).

These types of regulatory framework influence directly the decomposition of costs and revenue of all market actors, here in particular of DG operators and DSOs. This section seeks to schematically investigate the impact of DG/RES integration on the main cost and benefit streams of DG/RES

[6] based on its technological definition.

operators and DSOs. The focus of this section is to illustrate the effects arising from the interactions of different connection charging, network regulation and support schemes. This in turn influences the underlying incentives of market actors.

3.2 Cost and Revenue Streams of DG Operators and the DSO

Both for the DG operator and for the DSO, cost and revenue can be differentiated into capital expenses/income to be paid/received upfront and operational expenses/income to be paid or received as a variable component during operation of the plant. Notably, some of the expenses and income components are incurred either by the DG operator or by the DSO only whereas other components are passed through or allocated among them and other market actors, e.g., the TSO and consumers. The allocation of cost and revenue components impacts the risk exposure of the individual market actors.

The main sources of **revenue** for a **DG operator** are the national support schemes, provided the DG operator's eligibility, and/or the power price formed on the wholesale electricity market. Support schemes comprise investment support, i.e., capital grants, tax exemptions or reductions on the purchase of goods [5], and operating support, such as feed-in tariffs, tradable green certificate schemes and fiscal incentives (*Table 8*). Depending on the type of support, it may either be received upfront (investment support) or during the time of operation of the DG unit (operational support). The support instruments are for the most part granted on the basis of technologies, sometimes further differentiated according to capacity size. Frequently, Member States apply a combination of different support schemes and support levels across technologies. In terms of ***capital income***, in addition to *investment support* subject to national regulation, DSOs may provide locational signals by means of an *upfront locational premium* so as to induce DG operators to site new plants optimally from a network point of view.

The decomposition of ***variable income*** depends highly on the support scheme the DG operator is entitled to. Under the traditional *feed-in tariff* scheme, the price received by the DG operator per kilowatt-hour is fixed by the regulator and guaranteed for a specific duration, e.g., of 20 years. This means that the DG operator is not subject to wholesale price volatility and market forces, in particular, if the feed-in tariff is combined with priority access to the grid. In the case of a *price premium*, frequently applied as a technology becomes more mature and reaches higher levels of market penetration, a premium is paid on top of the wholesale market price. Additionally, DG operators often receive a fixed contribution per kWh for balancing costs. This induces DG operators to adapt their production more to fluctuations in market prices and demand, but also exposes them to a higher degree of price volatility on the wholesale market. A *quota system with tradable green certificates* is based on the opposite approach as compared to price-based mechanisms: the regulator determines a renewable energy target to be achieved as a percentage share of total electricity production. When selling power based on renewable energy sources, DG/RES operators receive a corresponding amount of green certificates that can then be traded on a green certificate market. In this regime, DG operators are exposed to both the volatility of the wholesale market power price and of the green certificate price formed on the certificate market. Further variable income may be obtained by means of a system service bonus for the provision of grid-stabilizing system services. Another consideration is congestion-related pricing which ensures a higher compatibility with network operation [25].

In analogy to the decomposition of revenue, the **costs** of the DG operator can be subdivided into capital expenses (CAPEX) and operational expenses (OPEX). CAPEX include the *investment costs* for the plant, equipment and possibly ground, a *risk premium* and *connection charges*. The DG operator incurs the latter for obtaining the connection to the network. The upfront capital investment is the highest in the case of a deep charging regime, where the DG operator has to pay both for grid reinforcements at the distribution and at the transmission level. A shallow charging approach only encompasses the direct cost of connection, i.e., the cost for new service lines to an existing network point [1]. Typically, costs for network upgrades are then recuperated through generator Use of System charges as a variable cost component, or socialized among users over time. Operational costs comprise *fuel costs* (if a fuel is required for operation of the plant), *operation and maintenance costs* (O&M), and the *network tariff* paid to the DSO for transport and system services.

***Table 8*: Cost and revenue of DG operator**

	Calculated expenses (cost)	**Calculated income (revenue)**
Capital (Upfront)	- Investment costs (plant, equipment, ground) - Deep/shallow(ish) connection charges - Depreciation costs - Remuneration of debt and equity	- Investment support (capital grants, fiscal incentives, price reductions on purchase of goods) - Upfront locational premium
Operational (Variable)	- Fuel costs - Plant operation and maintenance - Other costs (staff, etc.) - Network tariff (generator use of system charges and other tariff components)	- Operating support (feed-in tariff, price premium, green certificate price, tender, fiscal incentives) - Power price - System service bonus

As for the **DSO**, the **revenue** consists primarily of the *network tariff* subject to national regulation. In the case of deep connection charges, the DSO is able to recuperate all costs for network reinforcements, both at the transmission and distribution level, upfront from the DG operator. The operational revenue comprises generator and consumer Use of System charges as well as other network tariff components.

***Table 9*: Cost and Revenue of the DSO**

	Calculated expenses (cost)	**Calculated income (revenue)**
Capital (Upfront)	- Costs for reinforcements - Costs for network extensions - Costs for direct line of connection for new plant (transformers, cables, etc.) - risk premium for stranded investments - Depreciation costs - Remuneration of debt and equity	- Deep/shallow(ish) connection charges
Operational (Variable)	- Network operation & maintenance - Transmission use of system charges - Costs incurred due to losses - Ancillary service cost	- Use of system charges (generators and network users) - Other network tariff components, e.g., energy charges (rewarded per kWh), capacity charges

In terms of expenditures, as part of the DG-GRID project, Joode *et al.* [27] provide an overview of the **expenditures** incurred by DSOs: CAPEX consist of investments in distribution network assets, and the associated depreciation costs and remuneration of debt and equity. OPEX cover costs for using the transmission network (transmission Use of System charges), distribution losses, costs of ancillary services, costs for operation and maintenance, and possibly commercial costs in relation to energy management and billing of final customers.

3.3 Regulation Interactions and the impact on DG

In order to examine the impact of DG/RES integration on the main cost and benefit streams of DG/RES operators and DSOs, it is fundamentally important to distinguish

- Exogenous and endogenous components of their cost and revenue streams, that is, which components are fixed (e.g., feed-in tariff) or regulated (methodology for determination of access charge), and which components are subject to market forces, thereby implying a higher degree of investment uncertainty?

- The allocation of costs, i.e., are the costs appropriated by the DSO or DG/RES operator directly, or are they passed through to other market actors?

There are, as shown above, three types of government interventions in the market forces that shape the interaction between DG and DSOs:

1. Support scheme for DG $\rightarrow$ DG

2. Regulatory regime for DSO prices or revenue at aggregate level $\rightarrow$ DSO

3. Regulated charges (grid codes) for connection of DG and UoS charges for DG generation $\rightarrow$ DG + DSO

The choice of support scheme affects DG revenues and incentives directly. Simultaneously, it affects DSOs by the volume of DG investments. However, the DSO can only to a very limited extend respond to changes in the general level of DG subsidy to affect the DG investment level. Furthermore, there is only very limited difference between the subsidy regimes from the DSO point of view as long as they provide the same aggregate DG investment. Therefore, the conclusion is that the subsidy regime affects the DG but not the DSO, the latter being only affected by the general level of DG subsidy.

The regulatory regime affects the DSO directly in terms of prices (UoS charges) or the revenue. However, as this is the aggregate regulated price for all users on the DSO grid, it will not affect the DG generator very much as such. For the DG generator, it is crucial which specific charges it has to pay relative to the average charges incurred by all users. However, there might be specific details about the inclusion of DG related (public priority) reinforcements costs in the capital base (for allowed revenue) used for the DSO regulation. In general, the conclusion is that the specific choice of network company regulation does not affect the DG generator.

Contrary to these two points mentioned above, the regulation implemented in grid codes etc. for the connection of DG units and the UoS charges they have to pay have considerable impact on both DG generators and DSOs. This is the important channel for transfers of incentives. It is thus vital not to block this channel by inefficient regulation.

3.3.1 Support Schemes

Depending on the support scheme in place, DG/RES operators face different degrees of exposure to the volatility of market prices:

- **Feed-in tariff**: under the traditional feed-in tariff regime, DG/RES operators a feed-in tariff, T, preset by the regulator. T constitutes an exogenous variable. The only uncertainty that may persist is on changes in tariff levels and/or the regulatory regime. However, there is no direct exposure to price volatility on the market. Feed-in tariffs are frequently socialized among all electricity consumers, or financed through cross-subsidization by means of taxes.

- **Price premium**: if a price premium is applied, DG/RES generators obtain the electricity price, p_E, formed on the wholesale electricity market, and a fixed price premium, s, on top of the market price. The price premium is fixed (exogenous variable) whereas p_E is endogenously determined on the market. In some Member States (e.g., Denmark) for some technologies, an upper ceiling exists, that is, the sum of the electricity price and the price premium may not exceed a certain limit.

- **Quota system with tradable green certificates**: this scheme leaves the allocation to market forces; only the quantity of electricity produced from renewable energy sources is preset. DG/RES operators obtain the power price, p_E, and the certificate price, p_C, the latter being determined on the certificate market. Both variables are endogenously determined. The green quota can be imposed on retailers, electricity consumers or on power generators, i.e., the obligation can be on the production or on the consumer side [40].

Figure 1 schematically summarises the major regulatory interactions of DG and DSO revenue streams.

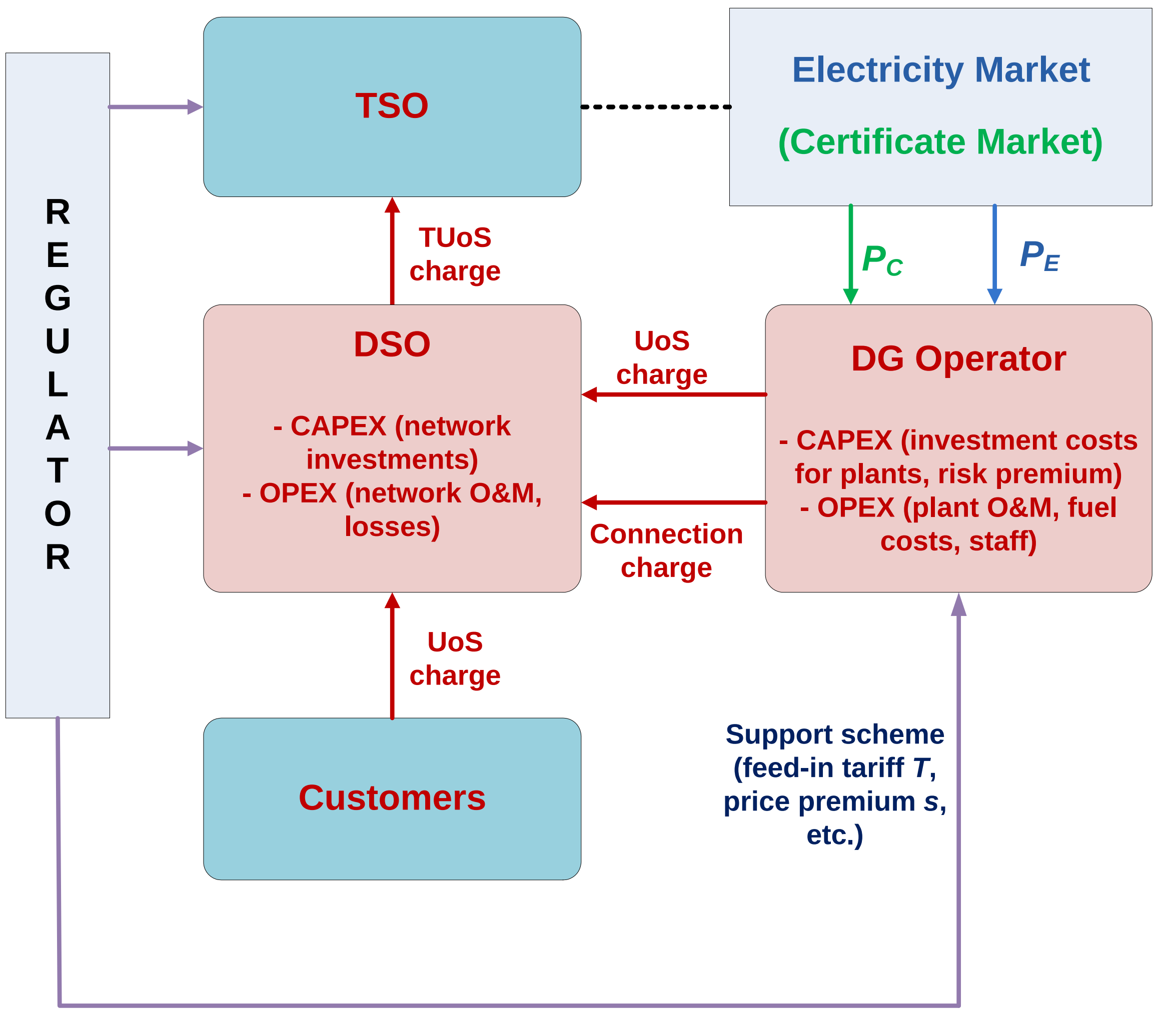

***Figure 1*: Major regulatory interactions of DG and DSO revenue streams**

3.3.2 Support Scheme Revenue Calculation Schemes

The profit of a representative DG operator consists of his revenue, depending on the application of national support schemes, and of the costs incurred for network connection and usage, plant operation and maintenance, fuel, etc. (Table 8). The main focus here is to illustrate the implications of different support schemes on the profit of DG operators. This section therefore abstracts from the detailed decomposition of investment and variable costs, which depend to a high a degree on the technological characteristics and network impact of a DG unit. Instead, emphasis is set on the extent to which prices are subject to market forces and hence endogenously determined, as opposed to being fixed by the regulator.

First, under a **feed-in tariff scheme** (case 1), a simplified representation of the profit function of the DG operator over the lifetime of a plant can be given by

$$\pi_{DG}(q) = \sum_{i=1}^{t} \left(T - c_{\text{var}} - UoS_{DG}\right) q_t - CC_{DG} - I_{DG} .$$

Due to its small size, it can be assumed that the DG operator constitutes a marginal installation, i.e., the production quantity q of the single DG operator does not exert significant influence on the market price[7]. In this simple representation, the DG operator maximizes profit by setting the production quantity q_t in each period[8]. The profit, π_{DG}, which the DG operator generates over the sum of its operation periods t can be decomposed into revenue, in this case in the form of a fixed feed-in tariff T obtained for each kWh of renewable electricity fed into the system, and costs. The latter comprise variable costs for the DG plant, c_{var}, UoS charges, UoS_{DG}, connection charges, CC_{DG}, and initial investment cost for plant and equipment, I_{DG}. Variable costs for the DG plant comprise costs for operation and maintenance, staff, and possibly fuel cost, amongst others. UoS charges are equally incurred per kWh and have to be paid by the DG operator if generator UoS charges are applied. In contrast to these variable costs (note that they are multiplied with the quantity of power generated, q), connection charges and investment costs for the plant are to be paid up front. The feed-in tariff is preset so that it constitutes an exogenously given parameter in the DG operator's revenue function.

In comparison, under a **price premium** scheme (case 2), the decomposition of revenue changes:

$$\pi_{DG}(q) = \sum_{i=1}^{t} \left(\tilde{p}_E + s_{DG} - c_{\text{var}} - UoS_{DG}\right) q_t - CC_{DG} - I_{DG} .$$

In this case, the DG operator receives the power price $\tilde{p}_E$, which is endogenously determined on the power market. This implies that only the price premium s_{DG} constitutes a fixed component of the DG operator's revenue whereas under the traditional feed-in tariff scheme this applied to the entire revenue.

[7] Naturally, with higher penetration levels of DG, this changes.

[8] Again, this being a simplified representation, we neglect the aspects of controllability and natural/operation variability of some RES and CHP technologies.

Under a **quota system with tradable green certificates**, the exposure to price volatility on markets is even more pronounced:

$$\pi_{DG}(q) = \sum_{i=1}^{t} \left(\tilde{p}_E + \tilde{p}_C - c_{\text{var}} - UoS_{DG} \right) q_t - CC_{DG} - I_{DG} \,.$$

Now there is no more fixed parameter in the revenue decomposition of the DG operator since the certificate price, $\tilde{p}_C$, is formed on the certificate market.

Theoretically speaking, *ceteris paribus*, the revenue of the DG operator would be identical for all three support schemes if the feed-in tariff (case 1) was equal to the endogenously determined electricity price plus the price premium (case 2), and to the sum of the power price and the green certificate price (case 3) under the assumption of perfectly functioning markets. From a practical viewpoint, though, inherent to the volatility of prices, investment certainty for DG/RES operators is the highest under a feed-in tariff scheme. If the impact on DG and DSO from support schemes are to be compared it must be based on the same assumption of the penetration that the support schemes will lead to. For the same levels of aggregate penetration, the concentration (location) of the new DG investment will be identical for the first three support schemes as they are production dependent. An investment subsidy makes the DG lifetime revenue less production dependent and therefore the location will tend to be more spread out in different DSO grids. This is preferable to the DSO but not necessarily from the overall efficiency perspective.

***Table 10*: Risk effect and support scheme preferences**

	DG	***DSO***
Fixed level FIT	prefer	no effect
Feed-in premium	increased variation	no effect
Feed in premium and Tradable green certificates	high income variation	no effect
Investment subsidy	prefer	prefer

The impact on the DSO is relatively limited due to the small impact on the DG decision where to locate their plant (investment) given that a certain level of investment is obtained by the scheme.

The general effect of the different risk perception for the DG is that it affects the level of investment, but this can be neutralized by adjusting the subsidy element in each of the schemes. Again, this does not affect the DSO. The reason for the DSO preferring the investment subsidy is the more diverse location of DG investment, due to the weaker link between generation and subsidy.

3.3.3 DG profits and participation in two markets under different support schemes

The risk impact on the relative preference for support scheme resulted in a DG preference for fixed feed-in tariffs. If the option for trading on different markets is introduced, this result might change.

The support scheme will influence the optimising behaviour of the DG in the way that it optimises its supply of the exogenous generation on the two markets. The more market based the subsidy scheme is, the more will the optimization be influenced by price differentials.

Indirectly this will influence the location of DG if there is any cost effect of having larger generation fluctuations, but we will leave this consideration to the end.
To illustrate this relation, a simple model of DG optimisation over two markets under different support schemes is sketched here.
Revenue for the DG with a feed in premium *P* and two markets consist of revenue from

- a day-ahead type spot market *S*
- and a regulating market *R*.

In the fixed feed-in tariff regime, the revenue will be independent on the access to the two different markets:

$$R_{DG} = q^{*}T \quad .$$

In the premium subsidy scheme, the revenue is depending on the prices on the two markets and the share α which is supplied on the regulating market:

$$R_{DG} = q^{*}P + (\alpha)q^{*}p_{R} + (1-\alpha)q^{*}p_{S} \,.$$

In both regimes the costs are the same, variable costs + connection charges (annualised) + investment costs (annualised), as given by:

$$C_{DG}\left(q^{*}\right) = c_{v}q^{*} + CC_{DG} + I_{DG} \,.$$

Total generation q* is exogenous and equal to q_S + $q_{R;}$ this could be interpreted as limited capacity or limited fuel resource. Revenue is based on revenue from the two markets and the feed in premium *P*. The premium is earned independent on which market the power is supplied to. That means no premium is lost for the generator.
Costs are identical in the two support schemes. The costs per unit are constant which means that output will be maximized as long as feed-in or feed-in premium plus market price exceeds the total average costs. Investment will only be undertaken in this case and generation set at the exogenous maximum. For a single DG unit this description is reasonable.
In the feed-in regime, all the generation will be supplied on the spot market as there are no incentives to get involved in trading on the regulating market.
In the premium subsidy scheme, there is an incentive to supply the generation on the market which is most profitable. If the price on the regulating market is higher than the price on the spot market, all generation will be supplied on the regulating market in case of the premium scheme. However, the premium could be adjusted to make the DG generator indifferent relative to the fixed feed-in case.

In a more realistic setup, the price on the regulating market has to be somewhat higher to compensate for the DG following the stricter rules for trading here (which implies higher transaction costs). Now if the price on the spot market is varying through time, but still providing the same average price that would leave the DG just as well off as under the fixed feed-in regime, the DG will face price differentials that are favouring supply on the regulating market when spot prices are low.
For these hours the DG will potentially earn less than under the fixed feed-in tariff system, but considerably more than if the output could only be supplied on the spot market.
So even if the spot market price average and the premium corresponds exactly to the fixed feed-in tariff, then the profit for DG will be higher under a the premium plus flexible market participation.

$$R_{DG} = q_t^* P + (\alpha_t) q_t^* p_{tR} + (1-\alpha) q_t^* p_{tS}$$

The suffix *t* denotes the time periods during an average year where prices on the two markets vary. In an example with total generation spread over three intervals with different relative price levels, the two subsidy regimes would produce different results.

$$\pi_{DG}(\alpha_t) = q^* P + \left(\sum_{t=1}^{3} (\alpha_t) q_t^* p_{tR} + (1-\alpha_t) q_t^* p_{tS} \right) - CC_{DG} - I_{DG}$$

The three periods exhibit the following three price relations

t1: $p_{1S} = p_{1R}$
t2: $p_{1S} > p_{1R}$
t3: $p_{1S} < p_{1R}$

As q^* is exogenous, optimising profits only means setting the three time period *alphas* at 0 or 1.

$$Max\ \pi_{DG} = q^* P + q_1^* p_{1S} + q_2^* p_{2S} + q_3^* p_{3R} - CC_{DG} - I_{DG}$$

$\alpha_1 = 0$; $\alpha_2 = 0$; $\alpha_3 = 1$

Without the option to switch between the markets, the DG generator would have suffered the low spot prices in period three. Allowing the trade on several markets as always allows to optimise the allocation of supply. This result is similar to the comparison of fixed feed-in and premium, where the generator (DG) is able to switch production not between markets but between different time periods with varying prices on the spot market. In the case given here, this is not possible as generation is exogenous in each period. This is the main advantage of premium subsidy schemes as compared to a fixed feed-in tariff when the (DG) generator is controllable.

If the fixed feed-in case is compared to the premium, in our case the average price levels would signal that the DG is just as well off under the fixed feed-in as under the premium system, but the DG will due to the switching between markets be better off under the premium subsidy regime.

From a societal viewpoint, the two situations imply that the subsidy under the premium system and the fixed feed-in tariff regime are the same because the net subsidy in the fixed case is total feed-in minus the spot market price.
Alternatively, the effectiveness of subsidies can be addressed in that the necessary subsidy to provide the same profit incentives is lower under the premium regime with broader market access.
For the DG, now the higher risk (annual variation) in revenue and profits in the premium case (referred to earlier) has to be balanced against the possibility of higher profits due to access to regulating markets in situations where spot market prices are low. This consideration is not reflected in our simple setting here. From a societal perspective, the risk is not relevant, but the contribution to both markets makes total adjustment cost for the power system reduced.

Finally, the consequences for DSOs can be considered. There are possible negative and positive effects. The variation of generation might become higher, but on the other hand the DG in increasing its own monitoring and controllability also might contribute to more precise generation plans and predictability in the local grid. The net effect is unclear and as many other factors highly dependent on the local grid properties. It is possible that the net effect in many cases will be negligible and therefore the total effect will be positive for the costs of the power system.

3.3.4 The DG revenue and rising connection charges with increasing DG share in network

One of the most important decisions affecting the interrelated costs between DG and DSO is the plant location in the specific DSO grid and the distribution of DG investment over different DSO grids. For this decision to be efficient one have to consider the *appropriate channel* for the DSO to affect DG location decisions. The operational decisions of DG can also have effects on DSO costs, but these effects are considered to be much less important and are excluded from this analysis.
As the parameters available to the DSO (connection charges and UoS charges) are regulated, they can not be set freely. However, there is no symmetry with regard to this as regulation allows the DSO to set charges as low as possible. Here, the focus is on a situation where there is a benefit accruing from DG in the grid at some locations relative to other locations or relative to other grids. In these cases, the DSO is able to provide incentives for DG localisation by reducing (or afterwards providing bonuses) for connection charges whatever the state of shallow, shallowish or deep connection charge allows.
There might be a preference for providing this discount up front relative to the use of more complicated discounts on the UoS charges for a specific location.

What is then the origin of the positive impact of a DG installation on DSO costs?

- Deferred or reduced reinforcement costs (consumer related)

- Network losses
- Reduced faults
- Reduction of other operating costs for DSO.

For the discussion here, it is assumed that the main potential cost reduction can be attributed to the possibility of reduced network losses. These are allowed as increased profits under the DSO regulation and thus will contribute also to the long term profits of the DSO.

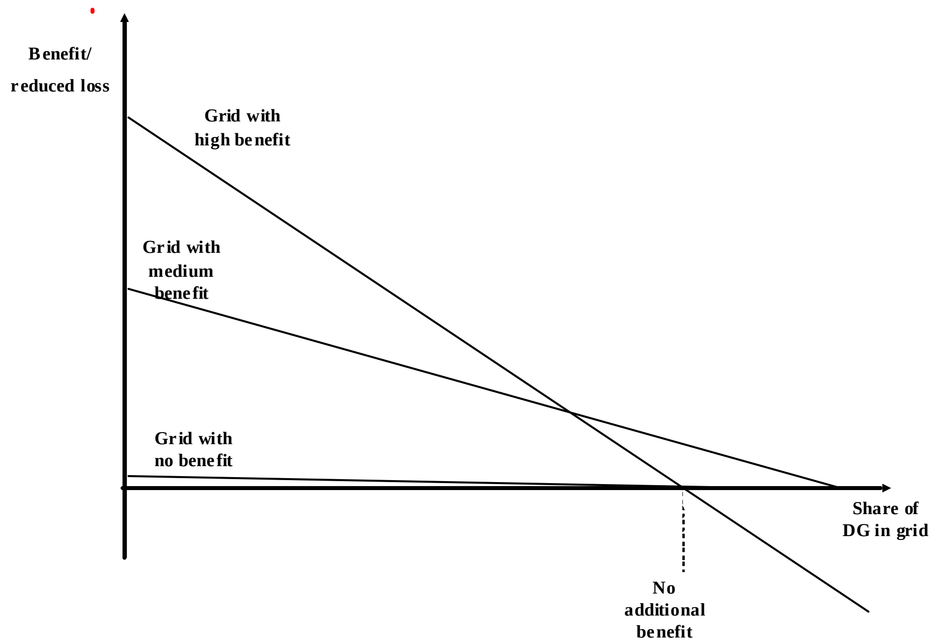

***Figure 2*: Possible network loss reductions in different grids**

The basic assumption is that network losses are reduced as initially generation is introduced in the grid. Gradually, as the share of DG in the grid relative to the load increases, the benefit for losses is reduced. At some level, the benefit turns into a loss as aggregate losses increase again.

Compared to network losses, it is assumed that the three other cost elements can be either positive or negative. However, this varies highly dependent on the conditions in each distribution grid, and none of them have positive contributions on average. They are therefore excluded from the general analysis here.

If network losses are reduced by the generation from DG at low levels of penetration and this benefit gradually fades away as penetration levels increase, then there is a need to pass this incentive on to the DG investor. The optimal investment would be to have different levels of penetration in the different grids depending on their characteristics.

With cost functions showing increasing costs in the share of DG in a specific DSO grid, investment will take place in more grids. As grid cost reduction potentials are exploited in the grid with best generation potentials, investment will take place in a grid with slightly less favourable generation conditions. The profit maximising DG generator will invest until marginal costs equal the marginal revenue of adding capacity. In reality, the revenue will be different in the grids depending on other factors, such as the wind conditions, heat demand, or local biomass resources. Here we assume these conditions to be constant so that only connection costs affect marginal costs for the DG.

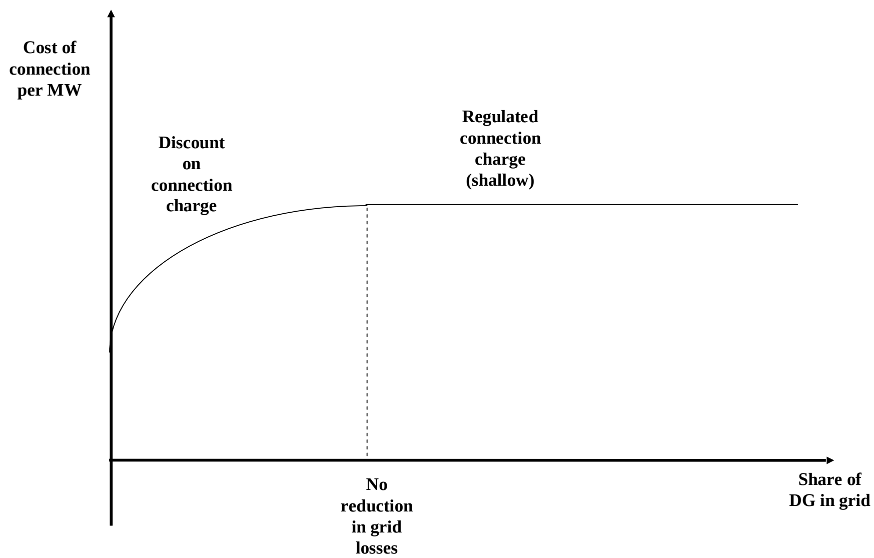

***Figure 3*: Gradually increased connection charges with increasing DG share**

This figure illustrates how marginal connection charges (net) are related to the accumulated share of DG in a specific grid. At a given penetration level, there is no more reduction of losses and if the DG share is further increased there will be increased losses. However, this is not passed on to the DG generator by means of further increasing connection charges, but capped with the regulated shallow connection charge.

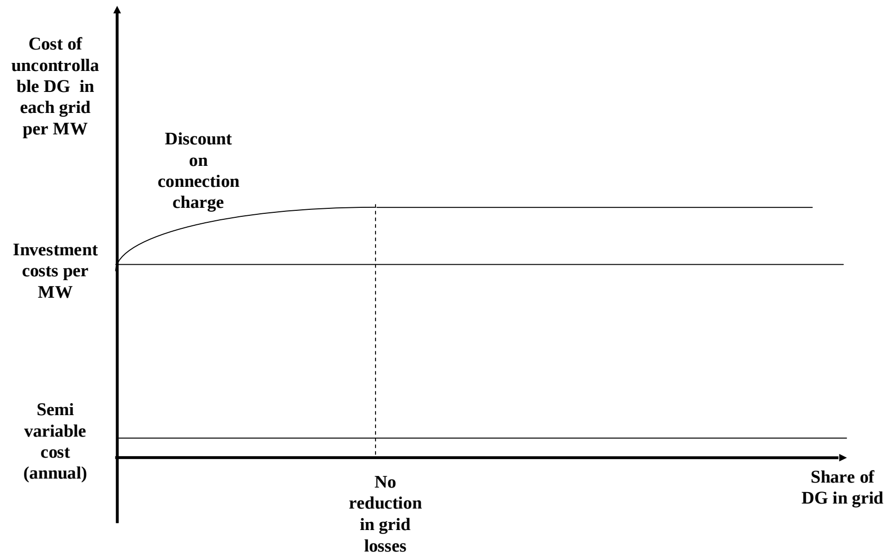

***Figure 4*: Long term marginal costs of DG investment in each grid**

This figure illustrates that total marginal costs for investment in a given grid is still characterised by the same gradual increase in costs, but at a higher level as the constant investment and semi-variable costs are included.

$$Max\ \pi_{DG} = \overline{q}P + \overline{q}\ p - \overline{q}\ CC_{DG}(\frac{\overline{q}}{L}) - \overline{q}I_{DG}$$

Profit maximisation implies maximising the premium revenues and the market revenues, which are constant per investment with costs increasing in the amount of investment. Costs will be rising up to the point where the connection charges are capped.

$$CC_{DG}(\frac{\overline{q}}{L}) = \min(a + \alpha\frac{\overline{q}}{L}, CC_{Shallow})$$

a is the base share of DG and $\frac{\overline{q}}{L}$ is the share contribution from new DG investment

The drawback of this representation is that there is not necessarily a maximum profit. Only if marginal revenue for the DG is less than marginal total costs including the capped connection charges, it will invest less than corresponding to the share of DG with no more network loss reduction. However, if the national level of penetration is as high as the situation with capped connection charges, the support element can be reduced. In reality, also the other rising marginal cost elements will secure that maximisation does not lead to 100% penetration of DG.

3.3.5 Curtailment and DG - DSO costs

Curtailment costs could serve as costs on marginal DG investment in a grid that needs reinforcement to serve peak generation from DG. With this disincentive to invest for the DG, the investment in several grids would be secured just as with the previous example of connection cost reductions. However, this solution is inefficient in that it provides no incentive for the DSO to invest. If the DSO, on the other hand, had to carry the burden of curtailment by compensating fully the generator, the DSO would become dependent on the support scheme.

On the negative side of cost interaction, there is a cost element of DSO operation that is dependent on the subsidy scheme for DG. If the curtailment cost of generation is to be (partly) borne by the DSO, the curtailment cost will be higher if under a fixed feed-in tariff. Under a premium or market + TGC scheme the market price will be lower at times of curtailment, and the cost for the DSO of curtailing will be lower as well. This is efficient from an economic point as the cost of lost generation is reflected in the market price at the given point in time, and not the average.

Curtailment is relevant in grids with high penetration of intermittent distributed generation. In Germany the recent changes in legislation have allowed the curtailment based on compensation of the generators. In this way, the DSO will have to pay compensation based on either the FIT or a market price. It is not evident how the imbalance payments are included in this compensation.

DSO costs for curtailment compensation will not be included in the revenue cap. The DSO will thus prefer a situation where the curtailment costs are minimized (market price subsidy regime) which will maximize their profits. If fully compensated, the DG will have no incentive to locate the investment to grids where this curtailment would not happen. It is also difficult to establish a channel whereby the DSO can shift this additional cost to the DG in a proportion that induces both location incentives to the DG and grid reinforcement incentives to the DSO. In most cases, some minor level of curtailment will be more efficient than overinvesting in grid reinforcements. One possible solution is to include curtailment of generation in the quality network regulation.

3.3.6 Network regulation approaches

The national network regulation sets the framework for the economic operation of a DSO. In the following, two topics are distinguished: first, how the total revenue of a DSO is determined. This is tantamount to setting average charges because it leaves the question open which customer group pays which level of charges. Secondly, possibilities of revenue recuperation among customers are addressed.

Three main categories of network regulation approaches are distinguished in the scope of this report: Rate-of-Return regulation (RoR), revenue cap incentive regulation and yardstick regulation. The following short description refers to the respective section in Deliverable D2 of the IMPROGRES project.

3.3.6.1 Rate-of-Return regulation

A **Rate-of-Return (RoR) regulation** is characterised by the fact that the regulator approves a cost base. A predefined interest rate is given on the bound capital. There are several practical applications of this approach: the regulator can take a rather light approach and control ex-post if the income of the regulated firm was reasonable, regarding its cost base and the allowed rate of return. The other possibility is that the regulated firm has to account for all costs in detail. The regulator will judge their reasonability and allow the predefined rate of return on the bound capital[9]. The latter approach tries to overcome the information asymmetry between the regulator and the regulated company with a higher administrative effort. It is regarded as the relevant RoR regulatory framework in the scope of this project as it reflects current practice in some European countries, e.g., in Germany (until 2008).

A formula to determine the revenue under a rate-of-return regulation can be as follows (based on [26]):

$$R_{i,t} = OE_{i,t} + D_{i,t} + T_{i,t} + (RAB_i * RoR)_t$$

The revenue R_i is composed of the operating expenses OE_i, depreciation expenses D_i, tax expenses T_i and the product of the regulatory asset base RAB_i and the allowed rate of return RoR_i.

A common critique to this approach is that there is an incentive to inflate the capital base (Averch-Johnson-effect) to reach a higher total profit. This means that a substitution of production factors takes place: a part of usual operational expenditure (OPEX) is replaced by capital expenditure (CAPEX). Both have an impact on the integration of additional DG/RES units; necessary additional investments may be welcomed by the DSO, whereas higher OPEX due to DG/RES (e.g., higher losses due to location in the network) may be seen critically. In the following, it is assumed that the regulator accepts all additional costs due to DG/RES integration and that the DSO knows about this, i.e., does not regard DG/RES connections with a risk premium.

3.3.6.2 Incentive regulation: Revenue and price cap

Revenue and price cap incentive regulation schemes lead to similar outcomes: the revenue is the average price multiplied by the quantity. A cap is commonly announced ex-ante to give the DSO a secure planning framework. If quantity deviations and therewith the revenue are adjusted ex-post to the actual outcome, both mechanisms are equivalent. This correction should take place because the DSO cannot be held responsible for the electricity consumption and generation of its customers. A general formula for the calculation of the revenue is (based on [26]):

$$R_{i,t} = (R_{i,t}\text{-}1 + AF_{i,t}) * (1 + RPI - X_{gen,i,t} - X_{ind,i,t}) \pm Z_{i,t}$$

The revenue Ri is based on the previous year's revenue $Ri,t\text{-}1$ and exogenous changes are corrected for with the adjustment factor AFi,t. This can comprise a change in the number of customers, a change in the amount of transmitted energy or network length. Furthermore, it does not have to be symmetrical, but can only regard positive changes: a negative development in the number of customers or the

[9] This approach is also referred to as Cost-plus-regulation in the literature; cf Viljainen, 2005, p. 16.

amount of transmitted kWh will not result in lower depreciations. The next part of the formula takes the retail price development *RPI* into account and sets the efficiencies for single distribution companies: $Xgen,i,t$ is a general efficiency requirement for the whole industry, whereas $Xind,i,t$ is an individual requirement for the single company which is based on a benchmarking with its peers. The final factor Zi,t reflects penalties or bonuses for meeting other objectives, e.g., with regard to quality of service levels. Notably, structural differences between firms need to be corrected for.

A core feature of revenue and price cap incentive schemes is the existence of a regulatory period: the X factors are set for several years in advance[10]. This way, the company has an incentive to increase its efficiency faster than the X requirements; the difference represents additional profit.

Several of the aforementioned elements interact with DG/RES units, as the following examples illustrate:

- Does an additional unit count as a new customer and thus increase AFi,t?
- Does an increasing share of self-generation (i.e., lower transmission through the network) impact AFi,t?
- Does the benchmarking methodology for $Xgen,i,t$ take DG/RES into account properly, both for capital and operating expenses?
- How are changes in the quality of service level (possibly contained in Zi,t) considered?
- How are necessary new investments due to DG/RES incorporated in Zi,t?
- Is it ensured that investments due to DG/RES do not turn into stranded costs when the unit stops generating before the part of the grid is fully depreciated?

In the following, it is assumed that the regulator accounts in principle correctly for the impact of DG/RES. From the DSO's point of view, a risk premium evolves as it cannot be sure that additional DG/RES units in comparison to the plan will be included correctly. The risk premium comprises the possibility for future changes of the regulatory system as well, reflecting the risk that systematic changes might worsen the position of DSOs with a high DG/RES penetration in comparison to those with a low one[11].

3.3.6.3 Yardstick regulation

The third major network income regulation approach is yardstick regulation. The usage of the term **yardstick regulation** evolved over time: the original concept suggests that a firm's revenue is based on the average revenue of all comparable firms [38]. This leads to a high efficiency pressure on firms, especially if the yardstick mechanism is applied annually and ex-post.

[10] The possibility of ex-post determination is also applied in some countries, but will not be followed in this report.

[11] This risk is symmetrical which means that it could also be a chance; as self-generation through DG/RES interferes with the core business of a DSO, a risk-averse DSO is assumed in this case.

An approach that derives from this concept is a partial connection to the firm's own cost, as expressed by the following formula (cf. [7]):

$$P_i = \alpha_i C_i + \left(1-\alpha_i\right)\sum_{j=1}^{n} f_j C_j$$

The average price P_i is calculated by a weighted average of the own unit costs C_i and the other companies' unit costs C_j, which are weighted with the factor f_j. The weighted average can be shifted by adjusting the factor α_i. This ensures that own costs will be taken into account and that the harshness of the original yardstick approach is absorbed partially. A practical difficulty in establishing such a yardstick regulation is how to determine peer groups of DSOs, i.e., how to account for structural differences between different monopoly's regions. The Dutch regulator has implemented a yardstick regulation avoiding this problem: first, it assumes that all companies are efficient. Then, it does not regard absolute efficiencies, but their development: a DSO with higher efficiency gains is allowed to recover higher revenue than a DSO with lower efficiency gains [36].

Generally speaking, yardstick regulation puts a higher economic pressure on the regulated firms. For this reason, it is assumed that the focus will not be on DG/RES development in the DSO area, but on efficient operation of the current network. Even if additional expenses due to DG/RES are neutralized, the risk premium from the DSO's point of view is estimated to be larger than for revenue or price cap incentive regulation.

3.3.7 Tariff calculation schemes

The previous section addresses the different regulation schemes for the calculation of a DSO's total revenue or average price. This section deals with the question how this overall cap is distributed among single customer groups.

According to Directive 2003/54/EC (Art. 20), the tariffs or methodologies for their calculation are approved ex-ante by national authorities. In all countries, customers are charged per capacity (kW) and actual energy transmission through the network (kWh). The underlying principle is that each customer should pay for his share of monopoly usage. However, differences which actors pay such charges prevail: consumers or consumers and generators are practiced approaches.

The implementation of this Directive differs among EU member states: Germany has issued a regulation which describes the attribution of network costs to single customer groups in quite a detailed way (*Strom-Netzentgeltverordnung*). In other countries like the UK and Denmark, the DSOs have their own calculation schemes approved by the regulation authorities.

The concept of classifying connection charges in the categories shallow, shallowish and deep is introduced in section 2.2.1. They correspond to DSO investment, which is depreciated over the expected lifetime of the asset. In the following, it is assumed that the income from connection charges is accounted for similarly. This avoids distortions in the size of the regulatory asset base, in other words: the DSO will not receive a return on bound capital if it is not its own bound capital.

For the sake of simplicity, the authors understand the regulatory system itself as stable –design changes with respect to DG/RES and changes in the force of regulatory control are nevertheless possible. Future income and expenses are discounted to present time *t*. Simplified income streams of a DSO are the following: the DSOs is modelled as having the purely economic interest of profit maximisation. DSOs with other objectives, e.g., cooperatives wishing to supply certain customer groups at minimal costs, are not covered.

The profit π is the difference between revenue *R* and expenditure *E*.

$$\pi_t = R_t - E_t$$

$$E_t = CE_{DG/RES} - CE_{others} - CAPEX_{other} - OPEX$$

Expenditure is composed of connection expenditure *CE*, which is in this case separated into expenditure related to DG/RES and other. The remaining capital expenditure $CAPEX_{other}$, e.g., for grid infrastructure replacements, and operating expenditure *OPEX* are subtracted.

$$R_t = CC_{DG/RES} + CC_{others} + \beta\left(\frac{UoS_{DG/RES}}{(1+r_T)^T} + \frac{UoS_{others}}{(1+r_T)^T}\right)$$

The revenue is composed of connection charges *CC* and use of system charges *UoS*. Both are divided according to their conjunction with DG/RES. The DSO obtains connection charges in the same period as the investment takes place, whereas use of system charges due to today's investments are recovered over the period *T* and therefore discounted with the interest rate *r*. The factor β represents a risk premium about the level of UoS charge recovery possibilities. It varies between the regulatory schemes and the impact of self-generation, as is explained below.

There are two possible designs with respect to UoS charges and increasing self-generation. A DSO perceives self-generation as a threat to its core business and therefore a strategic issue. Nevertheless, it should in theory be indifferent if it can charge all investments with the remaining use of system charges. The alternative is that a decrease in system usage results in less UoS charges. From the DSO's point of view, this is a risk that can vary with regulatory force. It is also included in the risk factor β, which is hence dependent on both the regulatory scheme and its enforcement.

4. Economic impacts of DG/RES integration on power markets

This section deals with the economic impacts of DG/RES integration. Firstly, considerations on the efficiency of several support schemes are discussed. Secondly, the basic working principles of the spot market are described and possibilities for DG/RES integration are highlighted. The same order applies for the following subsection on regulating power markets; the underlying balancing principles and possible participation on other ancillary markets are addressed shortly. Finally, the consequences of DG/RES integration on allegations of market power in power markets are discussed.

4.1 Efficiency of support schemes

When promoting DG/RES installations, policy makers may have several goals in mind. Among these can be:

- Reduction of greenhouse gas emissions
- Independence from imported fuels, i.e., higher security of supply
- Promotion of development of certain technologies
- Establishment of new industries with additional employment.

The instruments to reach such goals are chiefly measured by two criteria: effectiveness (e.g., if a certain RES penetration level has been met) and efficiency (what financial resources were necessary to reach an aim and what were the allocative implications?). These imply that a certain combination of DG/RES installed capacity or electricity production with a certain amount of expenses is aimed at. Efficiency can further be subdivided into static and dynamic efficiency: static efficiency focuses on a certain point in time, e.g., if a technological development is currently being supported with as little resources as possible to reach a desired level. Dynamic efficiency measures the technological development a support mechanism induces, i.e., if the costs of the energy decrease.

The effectiveness and efficiency of a support schemes depends highly on the maturity of the technology [32]: investment grants are suitable for technologies that are far from maturity, whereas FIT and price premiums can support the dispersion of a technology when they are closer to being economically viable on the market. Quota obligations can be the most efficient instrument for technologies when these have reached a certain market penetration and can compete on the power market. The report stresses that not only the kind of support scheme, but also the way it is designed and the predictability of future changes are major aspects for DG/RES operators. FIT tariffs minimize transaction costs and can be efficient if the tariffs are stepped and decrease over time. Quota systems can reach the goal exactly and lead to “minimal total RES-E system costs”, but not necessarily to minimal costs for consumers [32]. Interactions between such DG/RES support schemes and other energy policy measures like CO_2 quotas are the subject of ongoing scientific discussions and beyond the scope of this report [33].

Peculiar combinations between grid connection and DG/RES support schemes are an indicator for suboptimal efficiency with respect to the focus of the IMPROGRES project. Unjustified high negotiated connection charges could render projects uneconomical which the policy makers intended to support sufficiently. A counterexample is voluntary grid connection expenses by a DG/RES operator in addition to shallow connection charges. Such a case implies that the efficiency of the support scheme in combination with connection charges is not optimal, which is imminent to FIT and price premium schemes to a certain extent. A DG/RES investor could overcome organizational delays by voluntarily erecting a connection to a distant grid node. This way, the grid connection is ensured faster than waiting for the DSO to undertake similar measures. A similar case is reported from Germany, where a DG/RES unit erecting a connection grid is not bound by the same legal framework as a DSO. This led to a parallel DG/RES supply network without any final customer connections in a region [20]; the legitimacy of the DSO monopoly is challenged by a FIT support scheme at a level that allows the erection of a grid on top of DG/RES units.

4.2 Spot market

The national electricity spot markets offer a platform for wholesale trading. Their long-term counterpart is financial markets, which are mainly used for risk hedging. Spot markets facilitate actual power delivery and can be subdivided into several categories according to their time distance to delivery: day-ahead and intraday markets. The resulting market prices are also an indicator for the price level of bilateral electricity contracts (*Over-the-Counter*) due to arbitrage possibilities.

Both buyers and suppliers can bid staggered bids expressing what amount of electricity they desire to buy or sell in a certain hour if the price exceeds or falls below a certain level[12]. They will not necessarily buy or sell for the price they bid, but for the market clearing price – that is the price of the marginal unit which still needs to produce to cover demand. The resulting prices depend therefore on the equilibrium of supply and demand. If demand is low, only supply units with low marginal costs are required to operate (base load). In times with high demand, peak load with higher marginal costs will determine the market clearing price[13]. This can be easily understood when looking at the stepped supply curve in Figure 5.

The price effect of RES is also illustrated in this figure. Most RES are characterized by marginal operation costs of 0 Euro/MWh and will therefore always operate when meteorological conditions allow it. The same argumentation applies for CHP units which need to cover heat demand. In comparison to a case without RES, the necessary generation from conventional sources will be reduced. As the supply function is nonlinear, the price effects on the day-ahead spot market can be different: large RES generation in hours of rather low demand leads to a smaller price reduction than during hours with peak demand (see Figure 5). Following this argumentation, DG/RES can decrease spot market prices significantly: the unweighted average German spot market price was lowered by

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[12] Contrarily to most other European power exchanges, APX uses a half-hourly time resolution for the UK.

[13] The argumentation applies under perfect competition and without strategic behavior of market participants.

4.25 EUR/MWh in 2006 [37][14]. This corresponds to a decline of 61 € for every MWh generated from RES, which is the bulk of the average FIT support level of 99.5 €/MWh for the respective year.

Intraday spot markets are a means of correcting the day-ahead plans without having to use the regulating power market. Their age and maturity is different among the five focus countries. It can generally be assumed that a higher DG/RES penetration leads to a higher usage of these markets because market participants want to correct forecast errors without having to use the more expensive regulating markets. In a geographically small market, such forecast errors will show a high correlation among all units of a generation technology and have a uniform impact on market prices. A larger market can level this effect and financial expenditures and income from the intraday market can be more even for DG/RES units [24].

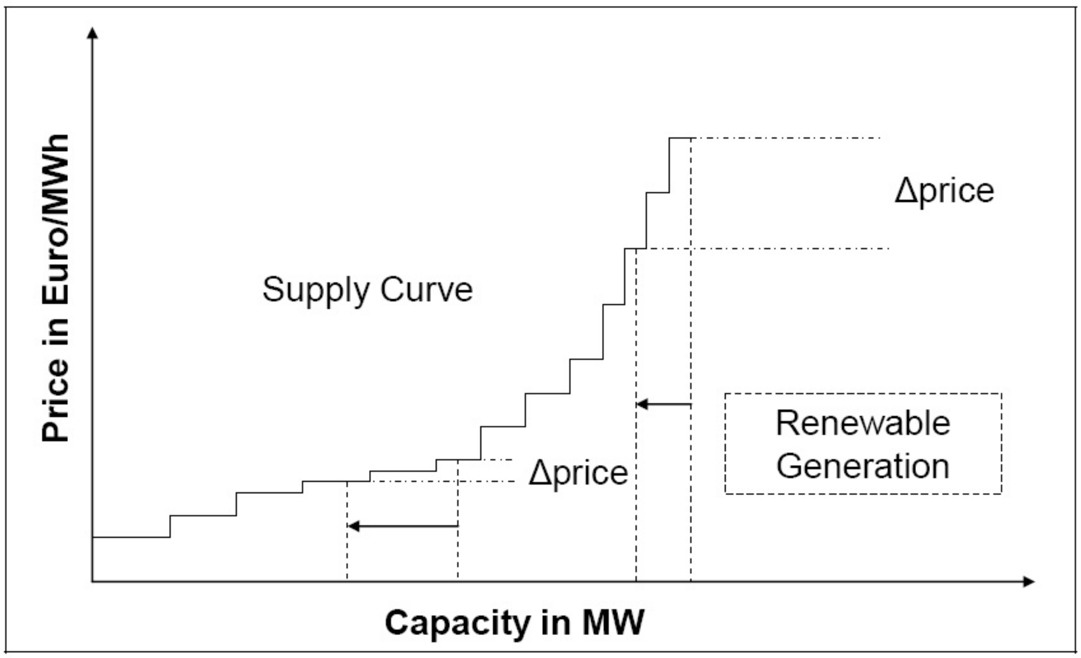

***Figure 5*: The effect of RES on spot market prices [37]**

The kind of participation of DG/RES in spot markets depends on the support scheme. Under a FIT system, the TSO or a regulator are obliged to buy all the electricity and integrate it into the power market by trading at the spot markets. It should be ensured that the other parts of a vertically not completely unbundled TSO do not profit from such an informational advantage. Under a price premium or quota system, DG/RES operators have to market their electricity. Special power exchange fees for clients with low trading volumes can support this integration. An alternative is that an agent bundles the generation of several DG/RES operators. This leads to higher specific transaction costs

[14] An underlying assumption is that the conventional power plant park is not adapted to increased generation from DG/RES [43].

than for large central power plants; furthermore, participation in balancing procedures and regulatory markets is necessary.

The major contribution to power prices from new additional capacity to power markets is of course a reduction of the price on the wholesale spot market. This also holds for adding new DG/RES capacity. As a major part of the investment costs of DG/RES are not recuperated on the spot market, but subsidised outside this market, the market will signal that no more capacity is needed by exhibiting lower prices. This distortion of price signals is only a distortion and a problem if we assume that DG investment has a lower capacity value than the investment that is not undertaken because it becomes unprofitable due to the reduced market prices.

4.3 Regulating power markets

The details and differentiations of regulating power are designed by national regulation and the national TSOs. For this reason, the following description of the regulating power market is an example how the market can be structured. The purpose of the regulating power market is the same everywhere: the correction of deviations from the schedule, i.e., the provision of additional electricity if frequency decreases, and reduction of electricity generation if the frequency increases. It depends on national market design when actors have the last possibility to correct their schedules on other markets – day-ahead or as close as 15 minutes ahead. In general, it is assumed that variable supply sources as most DG/RES increase the demand for regulating power due to meteorological forecast errors.

A first deviation from the nominal frequency of 50 Hz is corrected by primary regulated power. Primary frequency control has the aim of finding a new point of production and demand equilibrium to limit frequency deviations. This new equilibrium frequency is not (necessarily) equivalent to the frequency set point. In general, the responsible TSO has to ensure that the n-1 criterion is always met, which means that the largest generation unit in the grid can fail and be replaced immediately. For the UCTE synchronous area, the total primary regulating capacity is agreed to be at 3000 MW. Electricity producers can participate in a primary regulating power market, where their TSO ensures that his share of necessary capacity can be provided. Usually[15], only the available capacity (MW) is traded and energy delivery (MWh) is neglected. Up- and down-regulation are not distinguished. The main market features are minimum bid sizes (MW) if these can be cover several generation units and the period length when the primary regulating capacity has to be available (e.g., 1 or 6 months). Main obstacles for DG/RES participation in this market are too high minimum bid sizes and long bidding periods because intermittent energy sources will not always be fully available. An organisational hindrance can occur if the bidder has to ensure permanent staff availability for the bidding period, which is also derogatory for distributed resources.

Secondary regulating power replaces primary after a few minutes, if the deviation from the plan prevails. The purpose of secondary control is the restoration of system frequency to its set point value

[15] In some countries, such as The Netherlands, provision of primary reaction is obligatory for large generators and is without remuneration.

(50 Hz) and the power interchanges with adjacent control areas to their programmed scheduled values [34]. By doing so, the primary regulating capacity will be available again for sudden changes. Secondary regulating power is usually activated automatically by the responsible TSO. The offered capacity has to be fully available within 5 minutes. The market design differs from primary regulating power market's design: bids are separated for positive and negative regulating power and power (MWh) can be remunerated along with capacity (MW). Secondary regulatory power is traded in shorter periods than primary regulating power, usually day-ahead. In some countries (e.g., the UK) every plant is remunerated as it has bid on the market (pay as bid). In other countries (e.g., the Netherlands) the highest offers and the lowest bids determine the upward and downward regulating prices that every provider will receive. In both ways, only the cheapest available regulating power will be activated. Most DG/RES have to be grouped to so-called virtual power plants to be able to participate in this market; however, transaction costs are for this reason expected to be higher than for large central power plants.

Tertiary regulating power (or minute reserve) has to be fully available after 15 minutes and replaces secondary regulating power. The minute reserve will be used until the supply deviation is cleared, i.e., until the responsible actor could settle the difference on the intraday market. The market design is close to the secondary regulating power market: positive and negative capacities are distinguished as well as capacity and power payments.

Regulating power is traditionally supplied by hydro storages and large condensing power plants and organized centrally by the respective TSO. There are better possibilities for DG/RES to participate in minute and secondary regulating power markets, as these are rather short-term based. In most cases, this requires grouping them to virtual power plants and controlling them with necessary communication infrastructure. Participation in primary regulating power markets is even under such conditions hardly achievable because the offered capacity has to be available during the whole period.

4.4 Balancing mechanisms

Balancing mechanisms are the financial counterpart of regulating power. Every market participant – mainly producers for the supply side and traders for the demand side – has to make sure that his net balance with the network is as it has been planned. If all participants comply with their plans, no deviation and thus no need for regulating power occurs[16]. However, if two actors cause a positive and a negative deviation, only the net deviation needs to be corrected on the regulating market. The balance group contributing to system stability (like regulating power) receives a payment because it is providing a service, the balance group causing the deviation has to pay for it. There are several accounting mechanisms used in practice to implement these basic principles (e.g. [19]), which can lead to different financial impacts on producers and consumers. The amount caused by DG/RES depends strongly on the design of these principles and on the balancing implementation of DG/RES: Grouping

[16] This argumentation neglects possible short-term deviations between relevant moments of balance measurement.

various generation technologies from a large geographic area evens deviations of single units, whereas a low, regional aggregation of DG/RES units leads to a relatively larger balancing need.

In case that parts of system responsibility are taken over by the DSO (“active DSO”, [16]), DG/RES integration into regulating markets could be fostered institutionally as well.

4.5 Market power

Vertically integrated electricity monopolies have been replaced by competitive markets during the last 20 years. As natural monopoly characteristics prevail for the transmission and distribution systems, competition has only been introduced to generation, gross and retail electricity trade. Competition can also be introduced to markets which are traditionally part of network operations, e.g., metering services. This section focuses on gross electricity markets, where deviations from perfect competition prices and therewith the existence of market power has been alleged in various countries (for an overview, see e.g. [22]).

The possibility of exercising market power derives from a large market share. In such a case, a market actor can tend to behave like a monopolist, i.e., influence the market in a way that results will differ from fully competitive outcomes. Long-term financial power trading is a means of risk hedging of various market actors; the focus of the following paragraph is on the day-ahead spot market.

A common design feature of most European power exchanges is a common clearing price, i.e., that all bidders awarded with a contract receive the same hourly price, regardless of their actual bid. For the sake of simplicity, in the following argumentation generators are considered only and demand is assumed to be an exogenous function (see Figure 6). Single power plants are expected to be bid with their marginal cost, i.e., approximately 0 €/MWh for most RES, low levels for lignite and nuclear power and higher demand being covered by coal, combined cycle gas turbines and single cycle gas turbines. If demand is low (typically at night), base load power plant production will suffice for covering demand. During peak times, the plants with higher marginal costs will determine the clearing price at the exchange. Under perfect competition, these marginal costs are short run marginal costs (SRMC) and not the long-run marginal costs (LRMC), which contribute to amortise the generation unit. Base load power plants can recover their investment costs when the market clearing price is set by units with higher SRMC; the units with highest SRMC can only recover their investment cost through price spikes, i.e. when demand is equal to or higher than supply [22]. For this reason, there is an incentive for large market actors with several generation units to withdraw capacity, as Figure 6 illustrates: by withholding a power plant from the market, a generator will suffer a loss (difference between market clearing price and his marginal cost), but can obtain a much higher benefit because the remaining generation units will obtain a higher price. This, of course, implies that this generator needs a considerable market share.

The exercise of market power cannot be derived directly from a high market share and price spikes or a price level higher than SRMC can be due to a general capacity shortage. It is therefore hard to prove market power statistically and conclusions about market power in single spot markets can diverge considerably (see e.g. [22] and [30], for Germany or [23] and [41], for Scandinavia). However, it seems that concerns about market power decrease strongly when the capacity bid into the market is divided between as many actors as possible. If DG/RES capacities are not marketed through the trading divisions of large vertically integrated companies, they can help to disperse allegations of market power.

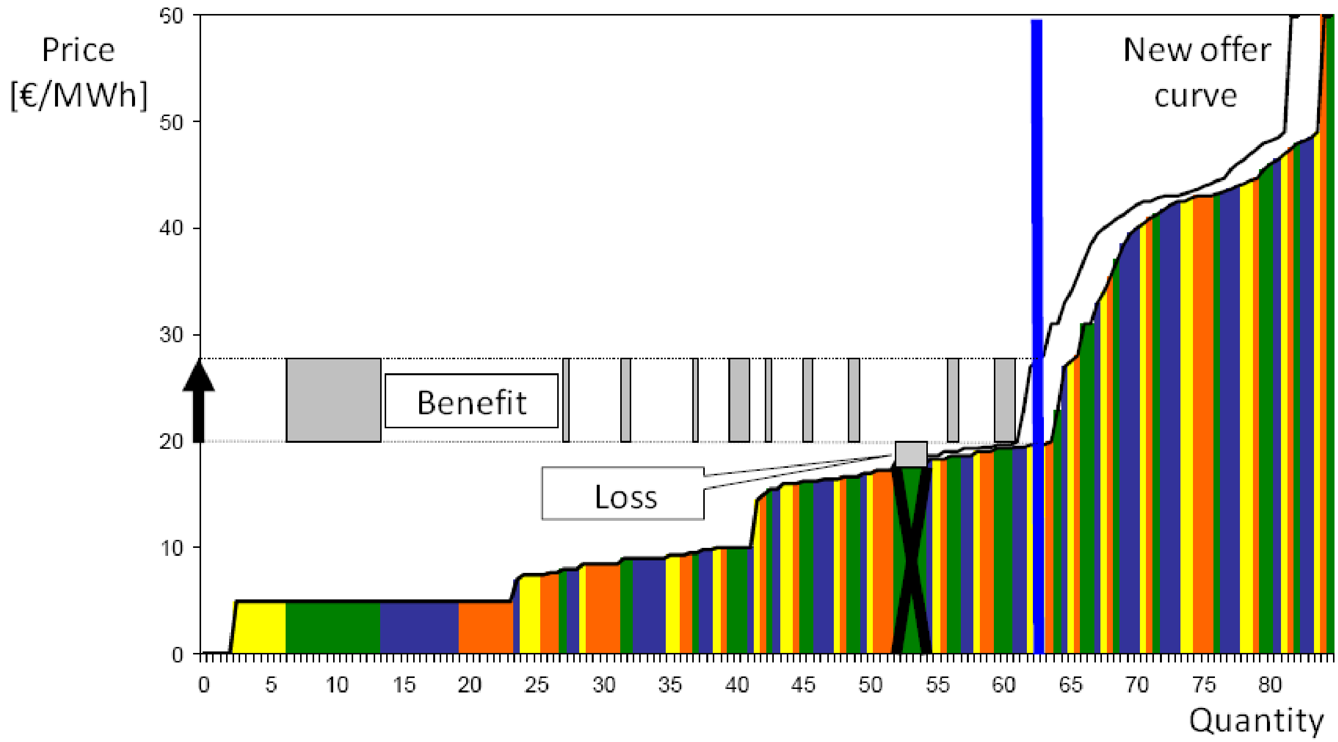

***Figure 6*: Example for possibility of market power exercise**
Source: [30], cited after [31]; own translation

Regulating power markets are nowadays characterised by a single buyer and large power plant operators, which have a considerable market shares in some countries. In Germany, the regulator concludes that these were "sharing the market peacefully" for a partial market [2]. The participation of DG/RES could therefore be positive to overcome assertions of non-competitive markets.

5. Final remarks

This report addresses various aspects of integrating distributed and renewable energy generation into DSO networks. Considering current EU energy policy goals in general and specific policy targets in particular, it is expected that there is a continuing need to integrate increasing amounts of this type of generation technologies in current electricity systems.

The detailed effects of a certain mode of DG/RES integration and market participation depends on a multitude of factors, e.g., penetration levels, existing network constraints, and the design of ancillary service markets. In general, it is possible to conclude that a sufficiently high DG/RES remuneration level (for example through support schemes) can ensure a fast penetration growth of the respective technologies and also help overcome obstacles such as high connection charges. However, DSOs should receive incentives to pursue a more active network management approach and to plan network expansion taking possible DG generation into account. As universally valid conclusions for DG/RES and DSO interactions are difficult to derive, the following reports of the IMPROGRES project will analyse several case studies.

For the provision of incentives to invest in optimal generation locations, DG/RES support should be generation based. To make DG operate in the most flexible mode, the support should be market based whenever possible. The higher risk perception is not seen as a major argument against market integration. Allowing DG to operate on both day ahead and regulating markets requires that DG generators are exposed to balancing costs themselves. If they operate on two markets simultaneously, they will be able to generate higher revenues, implying that possibly less governmental support is needed without obstructing further penetration of DG/RES technologies.

For the optimal location of DG in different DSO grids, it is assumed that there are positive network effects (cost reductions) from DG, at least when penetration rates are low to moderate. These cost reductions, for example from reduced network losses, must be allowed to contribute to the DSOs' profits. Network regulation must not undermine this cost reduction by depriving the DSO of these benefits. By the same token, the DSO should pass a share of this cost reduction to the DG generator by premiums or reduced connection charges for DG investment at favourable network locations or up to favourable levels (aggregate network loss reductions) of DG penetration in their grid.

With respect to curtailment of DG/RES production due to insufficient network capacity or faults, obliging the DSO to compensate lost revenue of the DG/RES operator gives the DSO an incentive to invest in network reinforcements. Full compensation in the case of fixed FIT will give too high an incentive to invest relative to the low market value at the time of curtailment. The market based support system will imply lower compensation payments and therefore lower network reinforcements, which is in line with the lower value of power at these times as shown by the market price. Too high compensation payments will lead to overinvestment in grid reinforcement. Some cost of curtailed power to the DG is beneficial to the optimal location decision. If the DG generator is always compensated fully there is no incentive to invest instead in a grid where curtailment will not take place.

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